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ENERGY FACILITY SITE
EVALUATION COUNCIL

November 1, 2003

Allen J. Fiksdal, Manager
Energy Facility Site Evaluation Council
P.O. Box 43172
Olumpia, WA 98504-3172

Dear Mr. Fiksdal:

Re: BP Cherry Point Cogeneration Project Draft EIS

I am a Birch Bay community resident and have attended the Scoping and Draft EIS public meetings in Blaine regarding the BP Cogeneration project. The air quality impacts to the Birch Bay community as well as the noise impact needs to be addressed in a way that can be understood by the community. I have been told that the EIS document is written so the public can understand the cumulative impacts of the project, but that is not the case. The public has been led to believe that all emissions will be reduced when in fact some of the more harmful pollutants (PM2.5) will be increased by an estimated 270 tons per year. The statement about reduction of total criteria pollutants would only be significant if the toxicity of each one was equivalent, which is not the case. The Birch Bay community has the right to be told the truth in language that is clear. The EIS should put this issue into context to ensure that it is undersood by the public. No health risks have been explained. The projected impacts on air quality and noise calculated by modeling must be followed up with adequate monitoring of the actual impacts on the Birch Bay community. 1

I would like to ensure that the EIS require the following:

- Clear language denoting which air pollutants would increase.
- A process for informing and educating a growing Birch Bay community of the potential acute and chronic health risks from PM2.5 especially to children and senior adults.
- A requirement for compliance and continuous monitoring of PM2.5 in specific sites throughout the Birch Bay community. 2
- A requirement to limit monitoring bias by requiring a PM2.5 quality assurance program. This will provide data with minimal bias so that decision makers and the Birch Bay community can address the concerns associated with fine particles in the atmosphere.
- A requirement for monitoring noise pollution making sure the actual impact meets the modeling expectation and promises.
- Emergency planning and risk management for the Birch Bay community due to an accidental catastrophic event or the release of ammonia stored or transported from the site.

The Birch Bay community is an urban growth area in Whatcom County and the population triples in the summer due to the seasonal/resort residemts, tourists and campers. Birch Bay is becoming a significant destination for retirement. Senior adults as well as children are more susceptible to the health risks of PM2.5. The cumulative impacts of this project need to be made very clear so that the Birch Bay community has the opportunity to understand its impact on air quality, noise pollution, wild life and the environment. I am asking the EIS to be clear and truthful and to educate, inform, plan and prepare for the short and long term impacts of this project on the Birch Bay community. 3
It is your reponsibility and our obligation to ask for nothing less.

Sincerely,

Doralee Booth

Doralee Booth
Birch Bay Steering Committee

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November 3, 2003

BP Cherry Point Project Comments
BPA Communications Office KC-7
POB 14428
Portland ORE 97293-4428

Dear Sir/Ms:

Here are corrected comments and attached exhibits regarding the BP Cherry Point Cogen DEIS, on behalf of the Washington State Association. An earlier version of these comments, without exhibits, was submitted earlier by attorney Gerald Steel.

Yours,

John Williams

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COMMENTS ON THE DEIS FOR THE BP POWER PLANT
PURPOSE AND NEED

One of the purposes and needs for this project is the need to provide the predicted additional electrical generation capacity for the future needs of the region. This projected need, according to the Northwest Power Planning Council's power forecasts for the region, predicted that by 2015, the needed regional increase in power would range from an additional 2035 megawatts (MW) under the medium prediction, to 4120 MW under medium-high, and 7507 under the high prediction.

However, those predictions are already almost two years old. Since those predictions were made, the following plants have gone on-line:

Chehalis	520 MW
Hermiston	650 MW
Frederickson	250 MW
Coyote #2 Springs	280 MW
Klamath Cogen	484 MW
expansion	100
Combine Hills	41
SP Newsprint	96
small projects	100

1

TOTAL 2521 MW

In other words, enough facilities with "firm" power generation have already been constructed to provide far more energy what would be needed for the next ten years under the "medium" prediction. In addition, another 519 MW of non-firm wind generating capacity have also been constructed.

NEWLY CONSTRUCTED WIND GENERATION

Stateline	119 MW
Stateline II	37
Klondike	24
Condon	50
Transalta	200
Nine Canyon	48
Vancycle	41
TOTAL	**519 MW**

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PARTLY CONSTRUCTED
The following gas-fired plants are also partly constructed:

Goldendale	250
Mint Farm	300
Satsop	650

TOTAL 1200 MW

At this point, the region has enough new energy facilities already running, and under construction, to meet the medium-high prediction for needed energy capacity for the next twelve years, and for the next 22 years under the medium energy needs prediction.

ALREADY PERMITTED
The following gas-fired plants are fully permitted

Sumas II	660
Wallula	1300
Umatilla	600
PGE	560
Port Westward	600
Plymouth	300
Col. River En.	44
Ore. Eng.	93
Boise/StH	141
West Linn	94

TOTAL 4400 MW

1 cont.

TOTAL RECENTLY COMMISSIONED, RUNNING, UNDER CONSTRUCTION, AND ALREADY PERMITTED: 8100 MW.

In summary there is already enough new energy generation built, under construction, and fully permitted, to supply even the highest prediction of new energy need for the next twelve years, and the medium-high prediction for the next 22 years, **without the BP project**. [1] These figures do not even take into consideration the thousands of megawatts of additional projects that are even now seeking permits, including but not limited to the Wanapa project, Calpine/Turner, Peoples Energy/Klamath Falls, and Coburg, which collectively add to another 3500 MW in capacity.

[1]The DEIS at Table 3-26 features a partial list of newly commissioned thermal plants, plants under construction, and plants fully permitted which totals 6504 MW. The DEIS list considerably underestimates the amount of current, under-construction and fully permitted generation, for instance by misstating the production of HPP, which is 649 MW, not 546 as claimed in the DEIS.

CONCLUSION
The DEIS fails to demonstrate a need for a 720 MW plant at BP to meet regional energy needs for the next 22 years, since more than enough plants have already been constructed, are under construction, are fully permitted, and are in the permit process, to meet even the highest predictions of energy needs. 1 cont.

ALTERNATIVE SIZE
One alternative that was rejected without an adequate discussion would be sizing the power plant to supply only the amount of electricity and stream that the refinery can consume.
The DEIS claims that a smaller plant would not provide economic energy, and would be an uncertain steam supplier. But not enough details were supplied to justify this dismissal of an important alternative.

Only an 85 MW plant was considered when this alternative was rejected. A slightly larger plant, for instance 100 or 200 Mw, which would provide more than enough energy for BP, and would also provide considerable excess stream generating capacity, and some energy for outside sales, was apparently not studied. If the plant were smaller, it could still supply its contractual obligations, but there would be less significant impacts, especially air emissions.

For instance, here is a list of several other cogeneration facilities which would supply an extrapolated 510,000 lb/hour of steam that BP needs, without producing the immense amount of air pollution and water use generated by the proposed 720 MW power plant

NAME OF FACILITY	MW	LB/STEAM/HOUR	Extrapolated* MW/510k lb/STEAM
Sun Mill, Okeelanta, Fla	75	1,300,000	29
UW-Madison	45	600,000	37
G-P, Camas, Wash.	11	140,000	39
Petro Canada Macay River	165	1,584,000	52
Hershey's, Oakdale, CA	5.6	50,000	56
Scott Paper, Everett, Wa	47	435,000	56
NIH	23	180,000	64
Coca-Cola Leesburg	3.6	22,000	82
Auburndale	7.2	44,000	82
UC Berkeley	24	100,000	120
Grays Ferry/Trigen	170	800,000	106
Aries	45	187,000	120
ExxonMobil, Baytown, TX	160	560,000	143
United Cogen, SF, CA	30	100,000	150
Carseland Cogen	80	264,000	152
Solvay/Jemeppe-Sambre	90	286,000	158

2

UW-Madison	150	400,000	188
Oxychem, Ingleside, TX	440	1,100,000	210
Bear Creek	80	165,000	242

*This figure is a scaled-up estimate of what megawatt plant would also generate 510,000 lb/hour of steam, given the figures presented for each particular facility. All plants except G-P/Camas and Scott Paper are natural gas fired.

100-200 MW PLANT WOULD MEET ALL THE PROJECT'S NEEDS
Based on the median generating capacity figure for these cogeneration plants, it can be extrapolated that a 100-200 MW facility is fully capable of generating 510,000 lb/hour of process steam for use at BP. In practice, this approximately sized plant appears to be in common use for steam generating hosts of this magnitude. At least six plants on the list generate over 510,000 lb/hour of steam and their energy capacity ranges from 45 to 440 Mw. For instance, the Petro Canada, ExxonMobil, and the Gray's Ferry cogeneration plants generate over 1.5 million lb/hour, 560,000 lb/hour, and 800,000 lb/hour of steam while generating 160-170 MW of electricity. 2 cont.

Only a single plant on this list is even half as large as the BP proposal. This information suggests that the BP proposal is clearly oversized, given the steam needs of the refinery, and the energy projections for the region.

A far smaller cogeneration plant of only about 20% of the proposed size of the BP plant, would be fully capable of meeting the purpose and need stated in the DEIS, while producing only about 20% of the projected air and water pollution, and water use.

ALTERNATIVE POLLUTION CONTROL–ELIMINATE AMMONIA THREAT
The power plant will store anhydrous ammonia, and emit ammonia for use in their SCR air pollution scrubbing system. This present dangers to public health and to air quality. The DEIS should have discussed several alternatives to use of anhydrous ammonia that present far less risk 3
to human health and safety. These alternatives include a non-ammonia scrubber system, use of aqueous ammonia, or use of urea.

AMMONIA STORAGE AND TRANSPORT
The proposed power plant will use, handle, store and transport large amounts of ammonia. Ammonia is listed on the EPA's list of extremely hazardous chemicals. The State of Louisiana has recently tightened regulations governing handling of ammonia.
It is prudent to minimize the use and storage of any hazardous chemicals such as ammonia. Nonetheless, BP proposes to transport, use and store large additional quantities of ammonia on site.

The DEIS is deficient in failing to describe and address the possible consequences of transporting, piping, storing and emitting hundreds of thousands of pounds of ammonia at this 4 facility every year. There are two issues regarding ammonia. The first issue is the constant release of ammonia from this facility under normal operating conditions. The second issue is the risk of ammonia releases from the storage and transportation of this hazardous chemical. 4 cont.

AMMONIA EMISSIONS UNDER NORMAL OPERATING CONDITIONS

Ammonia may be emitted from the project at 5 parts per million (ppm) which is one/half of the odor threshold. There are other ammonia sources in this area, including other power plants, and refineries, whose emissions could contribute to an ambient ammonia level. These other ammonia sources were not evaluated in the DEIS. In this case it is possible that the ammonia odor threshold could be exceeded under adverse air quality mixing conditions, such as inversions. These nearby ammonia sources should have been inventoried, because those sources 5
may cumulatively contribute to formation of secondary particulate.

But no controls for ammonia are discussed, nor is there any modeling that accounts for potential ambient levels of ammonia that would cumulatively join with the proposed facility's emissions. The impacts of ammonia emissions on PM formation were discussed earlier.

NON AMMONIA SCRUBBER SYSTEM--BENEFITS OF SCONOx WERE NOT ADEQUATELY CONSIDERED

SCONOX is an alternative pollution scrubbing system that does not use ammonia. SCONOX should have been comprehensively discussed as an alternative to the proposed project. The SCR system proposed for use by the Applicants results in a number of environmental problems that are reduced or eliminated with the use of SCONOx. These problems include: (1) hazards from accidental releases of the ammonia used in the SCR system during its transportation and handling; (2) the formation of particulate matter from the oxidation of SO_2 in the SCR catalyst; (3) the formation of particulate matter from reactions between ammonia and SO_2; (4) generation and disposal of the hazardous SCR catalyst at the end of its useful life; (5) inability to control NOx and CO emissions during startups and shutdowns; (6) increase in NO_2 from the use of dry low NOx combustor.

SCONOX would produce greater control of NOX and other pollutants, and eliminate ammonia 6
emissions, and the threat of releases from storage and transport of ammonia. The EPA has recently ruled that SCONOX is considered technically "Available" for NOX control on natural gas fired turbine power plants. The SCONOX controls on two UC-San Diego Solar 130S turbines, control NOx to 1.0 ppm or below, and also control CO to below .04 ppm, according to San Diego Air pollution Control District Source tests.

Although the DEIS rejected SCONOX based on cost, the California Air Resources Board BACT evaluation comparison reports for combustion turbines, rated SCONOX as only slightly more expensive than SCR.

LOW NOX BURNERS

The newest generation of low-NOx burners appropriate for power plants can reportedly lower

NOx emissions to below 5 ppm, without using ammonia and producing ammonia emissions and crating the hazards of ammonia storage and transport. The DEIS should have discussed these devices as an alternative. 6 cont.

THE DEIS FAILED TO CONSIDER HOW AMMONIA SLIP WILL ADD TO PM10 EMISSIONS

The DEIS failed to describe the reactions between SO3, NH3, and NO2, which form salts, some of which are emitted to the atmosphere and some of which deposit within the HRSG. Equations can be used to estimate a portion of the secondary PM_{10} that is formed from ammonia slip. Secondary PM_{10} can be formed by reaction of ammonia with SO_3 and NO_2 emitted by the gas turbines and present in the stack gases and plume as well as additional SO_3 and NO_2 that are present downwind in the atmosphere.

Additional ammonium nitrate could form from the reaction of NO_2 in the atmosphere with any emitted ammonia. This additional PM_{10} may not have been included in the Project's emissions estimates. Apparently the formation of secondary PM10, ammonia nitrate, from the proposed project, was not done in the DEIS, so the combined PM10 emissions will be more than what was estimated. BPA's own EIS on the Wallula Power project admitted ammonia emissions could produce as much as 460% of their own weight as secondary particulate. 7

AMMONIA EMISSIONS' PM_{10} FORMATION CAUSES VISIBILITY REDUCTION

The ammonia emissions from the proposed facility will contribute to the secondary formation of PM-10 in the project vicinity. The contribution of ammonia to secondary PM formation was not discussed in the DEIS. The fact that ammonia/PM reactions actually occur and cause visibility impacts is well documented in the technical literature. A noted atmospheric textbook, for example, contains this vivid description of the problem (Pitts and Pitts, 1999,[2] p. 284):

> "The formation of ammonium nitrate has some interesting implications for visibility reduction. In the Los Angeles air basin, for example, the major NOx sources are at the western, upwind end of the air basin. Approximately 40 miles east in the vicinity of Chino, there is a large agricultural areas that has significant emissions of ammonia...under typical meteorological conditions, air is carried inland during the day, with NOx being oxidized to HNO3 as the air mass moves downwind. When it reaches the agricultural area, the HNO3 reacts with gaseous NH3 to form ammonium nitrate..the particles formed by such gas-to-particle conversion processes are in the size range where they scatter light efficiently, giving the appearance of a very hazy or smoggy atmosphere even though other manifestations of smog such as ozone levels may not be highly elevated."

AMMONIA RELATED PM_{10} FORMATION ENDANGERS BIOTA

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[2] Barbara J. Finlayson-Pitts and James N. Pitts, Jr., Chemistry of the Upper and Lower Atmosphere. Theory, Experiments, and Applications, Academic Press, San Diego, 1999.

The majority of the ammonia slip reacts with NOx to form ammonium nitrate, which is a form of PM10. This PM10 can be deposited on surrounding hills, located immediately adjacent to the site. This is an especially significant impact, especially if there is already a high level of ammonia compounds emitted in the vicinity of the project. There are many other large ammonia sources in the vicinity of the project, including the Encogen, Tenaska, and March Point projects, and other power plants and large refrigeration facilities.

The Federal Land Managers conducts the IMPROVE air monitoring project in the Columbia Gorge area. IMPROVE's results show than almost 40% of fine particulate in the Gorge vicinity is made up of ammonia compounds; ammonium sulfate and ammonium nitrate. These same ammonia compounds could form additional concentrations of PM in the vicinity of the BP plant.

This additional PM10 would increase the Project's reported contribution to soil nitrogen. The impact of this additional ammonium nitrate has not been evaluated and must be to fully evaluate the environmental impacts of SCR. Ammonia emissions are discussed further in the following comments. These types of reactions, as described above, are a potentially significant impact that should have been discussed in the DEIS. 8

In summary, the DEIS appears to have underestimated the resulting concentrations of PM 10 from the project. These underestimations need to be considered in light of the Federal Land Managers certifications that significance degradation of air quality in nearby Class I areas are already being exceeded. This certification by federal agencies of an already occurring significant impact, that will be increased by the proposed project, was not mentioned in the DEIS

For these reasons, the subject of the health and environmental effects of PM-10 and the plant's contribution individually and cumulatively, should have been presented in depth. Many recently published studies demonstrate that PM-10 and TSP are far more harmful that previously considered. In one study of the Seattle area, days of high particulate concentrations in the air were correlated with increased hospital visits for asthma. In another series of similar studies, days of high particulate concentrations were correlated with days of high death rates in Santa Clara, California, Steubenville, Ohio, Birmingham, Alabama, and Philadelphia, Pennsylvania, among seven separate studies on this topic. Particulate have been recently, convincingly implicated in harm to pulmonary function.

IMPACTS OF INCREASED PM CONCENTRATIONS BELOW THE NAAQS NOT CONSIDERED

Some important conclusions from these studies is that harmful health effects occur even when particulate concentrations are far, far below the legal limits, there is no apparent particulate threshold for adverse health effects, and that harmful health effects are apparently caused by very minor increase in particulate concentrations. This means that even though the Project will not cause violations of the PM legal limits it could still cause significant health impacts. Construction will also create about 1 ton of TSP per acre of disturbance per month. Construction equipment, truck and car traffic related to this project, both in the construction and operation stage, will be an additional PM-10 and TSP source.

It appears from these studies that <u>any</u> increase in PM-10 and TSP levels will cause an adverse health impact. This is a significant health impact that should have been discussed in an EIS. There are important environmental impacts from PM-10 emissions, also. 9

<u>RISKS OF AMMONIA RELEASES</u>

The plant will store hundreds of thousand of pounds of ammonia on site, and millions of pounds of ammonia will be transported to this site every year. But the DEIS does not describe the likelihood of a transportation accident, the numbers of truck trips bearing ammonia, the possible size of any ammonia releases from a truck accident, the inability of this rural area's emergency response system to react to a large release, the neighborhoods and businesses that would be threatened by a release, or the risk and effects of a release from the ammonia tanks at the power plant, including the risk and effect of a tank failure. 10

In fact, the DEIS is virtually silent on this troubling subject, of large scale ammonia releases from transport and storage of large amounts of ammonia on the site, and how, or whether, emergency responses will be conducted. Ammonia releases are fairly common. A study submitted to the Congress revealed there have been over 1000 ammonia releases over one nine year period, which caused 801 injuries, 9 deaths, and 61 evacuations of over 22,000 people. [3]

For instance, there was a release of ammonia in August, 2001 from the Pratt & Whitney power plant in East Hartford, Conn., that caused the shutdown of nearby streets for five hours and led to the evacuation of 20 people. For this reason the commentors urge that the DEIS should have discuss ammonia hazards, and the ability to respond, from storage and transport releases, and any requirements to comply with the CAA amendments governing storage and transport of ammonia and other hazardous materials.

The facility will use anhydrous ammonia which is the most hazardous form of ammonia, and the type of ammonia most often implicated in releases causing injuries, deaths, and evacuations of thousands of people.

<u>AMMONIA ALTERNATIVES</u>

The DEIS evaluation should have studied alternatives types of ammonia to be stored and used, for instance the use of urea instead of ammonia, or the use of aqueous ammonia, and alternative transport methods for ammonia. Anhydrous ammonia should be specifically banned from use because of the increased dangers from its releases. 11

The DEIS' evaluation should also study the potential impacts of large scale ammonia releases 12

[3]Report to Congress Section 112(r) (10) Clean Air Act as Amended. EPA 550-r-93-002. December, 1993.

from different site locations, and the release impacts from different types of transport accidents. 12 cont.

SOME RECENT RELEASES OF AMMONIA (not a complete list)

evacuations	injuries	location	gallons released
1000	65	Quebec	" "
1500	0	Morro Bay, CA	300
100-300	n/a	Wauwatosa, Wi	n/a
125	n/a	Columbus Jct, IA	200
36	1300	Minot, ND	about 140,000
280	4	Washington, IND	Not provided
not known	15	St. Paul, MN	not provided
not known	9	Lorain, Ohio	10 pounds
230	5	Old Monroe, MO	not known
200	1	New Plymouth, NZ	not known

The Project may be subject to the Title III requirements regarding storage of hazardous materials, but those requirements, including a hazard assessment and risk management program, have not yet been developed and reviewed by the public and the relevant agencies. These requirements should have been fulfilled in time for these proceedings, so that the public can evaluate this project's risks in a single round of reviews and meetings. 13

ALTERNATIVE DESIGNS TO REDUCE WATER USE AND DISCHARGE

The proposed plant will use water cooling. It will consume an average of over 2200 gallons per minute of water; or more than 3 million gallons per day. It will also discharge about 190-260 gpm. (About 300,000 gallons/day)

Over 2200 gallons/minute (Over 3 million gallons per day) is a very high rate of water use for this size of power plant. Many power plants are designed to generate far more energy, while at the same time using far less water than is proposed for this plant. For instance, the proposed natural gas fired Chehalis power generates almost as much energy (520 vs 720 MW) as the BP proposal, but will use only about 7% as much water. The Chehalis plant is solely air cooled.

Many power plants are also able to function without discharging 200 gpm or more of waste water, also, including the Sumas I plant. The DEIS should have more comprehensively discussed alternative designs of the facility that would reduce water use and discharge, as follows. While the DEIS rejected these alternatives as too costly, the widespread use of these water conservation methods indicates that any increased costs are relatively insignificant. 14

For instance, the BP facility will use far more water to generate 700 MW, than will the Lakefield Junction plant in Minnesota, to generate over 600 MW. Diamond Energy's Nevada plant will use only 20-50 af/year (about 40,000 gallons/day) to generate 500 MW, according to published accounts. Colorado Springs/Fountain will use only 80 gpm to generate 480 MW, compared to BP water use of over 2000 gpm, (well over 3000 af) according to published accounts.

If many other power producers can bear these slightly increased costs, and in the process conserve billions of gallons of water, than the DEIS should conduct a more stringent review of the purported reasons for rejecting water conservation measures out of hand. 14 cont.

AIR COOLING

This alternative would include complete air cooling, rather than partial water cooling for the facility. The commentors are aware of many existing and proposed power plants that are solely air cooled, including the two Neil Simpson plants and the Wyodak plant in Wyoming, the permitted Chehalis Power facility in the State of Washington, the Doswell facility in Virginia, the Matimba and Kendal powerhouses in South Africa, the Rosebud plant in Montana, the Linden and Sayreville plants in New Jersey, Colorado Springs near Fountain, Colorado, Diamond Generating, near Goodsprings, Nevada, Duke, and Miriant, both near Las Vegas, Reliant's Choctaw County projects near French Camp, Mississippi, and its Hunterstown, Pennsylvania, project, Taiyuan #2 in China, Trakya in Turkey, Uran III in India, Tousa in Iran, and the Camarillo facility in Ventura County, California.

In addition, most large power plants permitted recently in California have been exclusively air cooled, including Sutter Power, and Otay Mesa. Total Air cooling of the BP plant could reduce water use by 70% or more, and would save about 2 million gallons/day.

HYBRID COOLING SYSTEMS

These plant designs use a combination of both air and water cooling, and are in use at the West Cogeneration plant in Germany, and the Exeter Energy plant in Conn., USA. Three Mountain Power is California is another hybrid cooled plant, as is Mass Power's Indian Orchard plant. Water use is cut approximately in half.

ZERO DISCHARGE PLANTS

These types of facilities extensively re-treat and re-use their waste water, often with the reverse osmosis membrane process. Public Service in New Mexico has employed this technology for over 20 years, as does the Massena. New York plant, Ocean State in Burrillville, Rhode Island, and FJ Gannon in Florida. There are several variations on this process, including brine concentration. We understand that HPD plant, in Naperville, Illinois, uses this process. Staged cooling, used at Pasco in Dade County, Florida employs this alternative. The nearby Sumas I plant is zero discharge.

The DEIS rejected zero discharge after a truncated discussion that concluded the costs of trucking out waste water solids was too high. The treatment plant for this effluent is going to have solids that will need trucking and disposal, in any event. This was not an adequate discussed of an alternative that would not require the commitment of this massive amount of water for the power plant, and which is in active use at many other competitive power plants. 15

WATER QUALITY AND QUANTITY IMPACTS

The DEIS at 2-27 states that the waste water will have to be concentrated at a ratio of 15-1 before it will be discharged. The water tests in the DEIS did not present an analysis of the trace metals and radioactive materials that may be finally present in the cooling water. Even if these types of materials area present in very small amounts, they will be concentrated by 1500% by the cooling cycles, and this activity could produce a significant concentration of potentially toxic materials in the discharge water. 16

WETLANDS

The DEIS claims that about 30 acres of wetlands will be destroyed by the project, and about 100 acres will be rehabilitated. Again, however, the DEIS fails to inform the reviewers that the degrading of these and directly adjacent wetlands, and the ultimate rehabilitation of other wetlands, is actually the product of two contemporaneous projects; the cogen plant and the isomerization (Isom) unit.

In fact, the Isom unit is currently undergoing its own review by the Army Corps of Engineers, whom admits that the construction lay down area, and the resulting lost wetlands, for the Isom unit (the Brown Road Materials Storage Area)is next to the lay down area, and lost wetlands, for the cogen unit. The wetlands areas proposed for rehabilitation for both the Isom and Cogen units are also contiguous, north of Grandview Road. 17

But the DEIS fails to discuss the cumulative impacts of the Isom and the Cogen projects on any resources, including but not limited to wetlands. For instance, the proposed cogen laydown area west of Blaine Road would appear to conflict with the proposed plans for wetlands water conveyance that are part of the Isom project wetlands mitigation plans. 18

SOME REHABILITATED AREAS ARE EFFLUENT TREATMENT PONDS, NOT WETLANDS

The DEIS admits that effluent from the cogen's oil-water separator will be discharged to the ponds in CMA-1. The DEIS claims these and other areas provide rehabilitated wetlands which mitigate for the losses of over 30 acres of natural wetlands. But if an industrial uses a ponded area to receive effluent, the recipient area is part of a wastewater treatment plant, not a "wetland." In summary, some of the claimed "mitigation" wetlands are not really wetlands, those ponds are actually water treatment facilities.

For this reason, Ecology publications state that "wetlands" created for stormwater treatment are "high risk" because they may receive high sediment and debris loading, or may accumulate toxic materials and become dangerous to wildlife. For this reason much higher replacement ratios are justified. (DOE Publication 92-8, p.14) The DEIS should describe what acreage of rehabilitated areas are being used for receipt of stormwater, so that commentors can determine if an appropriate replacement ratio of wetlands is actually being provided. 19

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DEIS FAILED TO CONSIDER CUMULATIVE IMPACTS WITH THE ISOM CONSTRUCTION AND OTHER RAPIDLY UPCOMING CLEAN FUEL PROJECTS

The DEIS' failure to discuss the closely related and physically adjacent Isom construction job and its impacts, and the other elements of the ongoing Clean Fuels projects at BP and the neighboring refineries. All of these project will have cumulative air quality, traffic, and socio-economic impacts in combination with the impacts from the BP Cogen. The DEIS' failure to discuss these cumulative impacts violates NEPA (40 CFR 1508.7) and SEPA, which both require a study of cumulative impacts of nearby projects taking place at the same time. 20

PIPELINE IMPACTS

The proposed power plant and its support facilities include a natural gas pipeline lateral. There are many other natural gas pipelines around the country, and in the Northwest, that were constructed according to federal standards. But in the Northwest alone, pipelines have blown up three times within the last few years.

A pipeline near Bonneville Dam exploded and burned on February 27, 1999. The roar from the explosion was heard for two miles. The 300 foot high fireball was so huge it was visible for miles. Route 14 in Washington was closed to protect the public. Press accounts state that earth movement from recent heavy rains may have been responsible for the pipeline break. The fire destroyed a resort hotel that was under construction and a nearby dwelling.

Near Kalama, Washington, a natural gas pipeline broke in February, 1997. Again, a 300 foot high fireball blazed into the sky. And just one day earlier, the same pipeline exploded and burned near the BP site, Bellingham, Washington.

In March of 1995, that same pipeline had raptured and blew up near Castle Rock, Washington. After that 1995 explosion, the company removed soil from 300 feet of the pipeline, to relieve any stress. But less than two years later, it blew up again. Again, soil movement was the cause of the pipeline breakage, according to published accounts.

There have been a total of at least ten large natural gas pipeline explosions, since 1978 in the Northwest, including other ruptures in Stevenson, Washington, La Grande, Oregon, and Montpelier, Idaho. All of these explosions have been on the Williams Pipeline system that may supply this proposed power plant.

A few years ago, a construction backhoe caused a leak in a Northwest Natural Gas pipeline recently in Rainier. Seventy five people were evacuated. There is other evidence regarding the potential impact on public health and safety from natural gas pipelines.

Earlier this year, at least six people were killed in a natural gas pipeline explosion near Carlsbad, New Mexico, and another six were injured. Landslides in Ventura county, California ruptured several natural gas pipelines in February, 1998, again after heavy rain. Between 1965 and 1986, there have been 250 pipeline failures in the United States as a result of stress corrosion cracking, caused by a combination of water, soil types, and gas temperature within the pipelines.

Twenty-one people were killed during 1995 from natural gas pipeline accidents.[4] A Transwestern Pipeline natural gas pipeline exploded on August 20, 1994 in New Mexico, near the Rio Grande River, damaging a bridge. An October, 1994 explosion of a pipeline in Torrance, California, injured 30. A December, 1989 pipeline rupture caused by a farmer's plow, triggered the evacuation of 600 people in Butler, Illinois.

In March, 1994, a natural gas pipeline exploded in New Jersey, killing and injuring scores of people and creating a 30 foot deep crater and a fire that destroyed eight buildings and severely damaged six more buildings.

All of these pipelines were constructed to federal standards, and monitored by federal agencies. The DEIS should explain, how with all the mitigation measures and careful engineering, pipelines, including facilities in Washington State, on the very pipeline that will service this power plant, can still blow up. When these events occurred in a populated areas, there may be heavy loss of life and property. These pipeline explosions are significant impacts. Additional protective measures should be discussed and implemented, and the problems that caused this explosion should be carefully explained at length in an revised DEIS. 21

But the DEIS did not discuss pipeline accidents, also known as "service incidents."
A service incident is reportable if there is a gas leak causing a death or serious injury, gas ignition, over $5000 in property damage, if it occurred during a test, if it required immediate repair, or if a portion of the line was taken out of service because of the incident.

An revised DEIS should be prepared to describe the likely scenario of service incidents on the pipeline serving the power plant, perhaps by describing several of the recent explosions on this pipeline and at similar pipelines. 22

Descriptions of a range of several recent incidents should be provided, so that readers and commentors can be appraised of the possible impacts of service incidents. This is appropriate because service incidents can be expected over a 50 year life span for these pipelines. The DEIS should also have discussed whether, and how local agencies in this area would respond to a pipeline explosion and fire. 23

POWER PLANT ACCIDENTS

The DEIS failed to discuss the potential for accidents and explosions at this proposed facility. On occasion, similar power plants have experienced fires and explosions that have damaged property and killed people.

On October 8th, 2002, a massive explosion at the Florida Power & Light natural gas fired Palm

[4] New York Times, 4/9/97, p. 1.

Beach plant rocked two counties, followed by a hydrogen-fed fire. The explosion shook houses and rattled windows, and was as loud as a sonic boom. In January, 2002, there was a hydrogen explosion and a resulting fire at the natural gas fired BC Hydro plant in Port Moody, BC.

Less than two weeks ago, on October 1, 2002, there was a nine-alarm fire at the Sithe power plant in Boston, that began in a hydrogen generator. The fire and explosion caused $10 million in property damage.

The BP DEIS does not apparently even mention the use of hydrogen at that plant, or list it as being stored on site. We understand that hydrogen is routinely used and stored at natural gas fired and other power plants similar to BP, including but not limited to these three plants, that have blown up recently. But this potential impact from explosives and fires from caused or fed by hydrogen, and the impact on emergency services to respond, was not adequately discussed in the DEIS. 24

At the Sithe blaze, 180 firefighters had to respond. The natural gas fired turbine at the Doswell power plant in Virginia recently suffered an catastrophic fire and explosion. It took 75 fire fighters to quell the resulting fire The DEIS should have discussed what will happen if hundreds of fire fighters are needed to respond to a problem at BP.

There were other explosions and fires at power plants recently. An explosion and fire rocked the Black Hills Power and Light power plant in Wyoming, in June, 2002. A back-up generator blew up and caused a "major" fire at the Allegheny Energy plant in Pennsylvania, in July, 2002. Firefighters from at least five communities had to respond to the blaze. A pressure relief valve activation at the Mirant plan in Zeeland, Michigan in August, 2002 caused diversion of traffic, to avoid released gasses.. Three workers were killed at a fire in the O'Brien Newark, New Jersey Cogeneration power plant fire recently. At least 20 other fires have been recorded over the last 10 years at power plants, causing another death and $417 million in property damage. The most severe fires often involved the release of lube oil, which ignited. Thousands of gallons of lube oil will be stored at BP.[5]

There were 272 to 557 equipment failures and accidents per year at power boilers and pressure vessels since 1992, causing almost 200 injuries and 29 deaths, and another 145 to 387 failures, and another 270 injuries and 54 deaths, from unfired pressure vessels, according to Power Magazine, Jan-Feb., 2001, p 53.

Because Power plants typically store and use many materials that present a danger of fire and explosion, such as hydrogen and lube oil, some of these hundreds of annual accidents at power plants cause injuries, and losses of life and property beyond the power plant boundaries, and require a large response of emergency personnel, as previously described. The dangers from the use and storage of these materials, and even the types of materials to be stored at BP, and the 25

[5]Most of these narratives are from the Chemical Safety Board's web site.

ability or lack thereof of local fire departments to respond, was not discussed in the DEIS. These kinds of serious accidents are significant impacts that should be discussed in an EIS. 25 cont.

CUMULATIVE EFFECTS OF INCREASED USAGE OF NATURAL GAS

The EIS did not discuss the adverse impacts from the increased exploration and processing of gas in Canada, in part sparked by the development of these this project.

Discussions of Canadian impacts is mandated by Presidential findings during the Carter Administration regarding the scope of NEPA-covered projects. A description of Cross-border impacts are also appropriate, considering that the Canada Energy Board requires assessments of impacts in the United States, when evaluating proposals for Canadian pipelines. 26

Nor did the DEIS adequately discuss the cumulative impacts of this project and the many other power projects in the Northwest, on the natural gas supplies. Although this very topic was the subject of a chapter in the Wallula Power EIS, it received inadequate discussion in this document, even though the cumulative impact of some of the recently proposed power plants in the Northwest, was the additional consumption of over 6% of domestic natural gas reserves.

PM-10

ADDITIONAL PM SOURCES

. The DEIS also lacks adequate information to assure commentors that its calculations included the impact from formation of secondary PM by conversion of ammonia. While the DEIS did discuss secondary formation of PM from conversion of nitrogen and sulfur compounds, the DEIS did not discuss secondary formation of PM by conversion from airborne ammonia compounds. 27

This plant will emit hundreds of tons per year (TPY) of PM-10 from its turbines alone PM-10 is fine particulate that is capable of being drawn deep into the lungs. PM-10 is highly damaging to human health. But in addition to the power plant exhaust, there are other sources of PM-10 and total suspended particulate (TSP) from this project, including the cooling tower.

COOLING TOWER DRIFT

The cooling towers are PM-10 and TSP sources, to the degree which the cooling water contain solids, which are emitted from the cooling tower exhaust as particulate. A large power plant using water high in solids content can emit many tons per year of PM-10 and TSP. For instance the Goldendale Energy plant was predicted to emit 6.6 TPY of PM, and BP is 300% larger. The PM emissions from the cooling tower will contribute significantly to the ambient air concentrations of PM_{10} concentrations. The effluents have low exit temperatures, low exit velocities and correspondingly are low in momentum and buoyancy. Switching to full air cooling would also reduce PM and TSP emissions, since a cooling tower will no longer be needed. 28

Cooling tower emissions also contain salts, metals, water treatment chemicals, and other contaminants, which could degrade the quality of soils, and affect human health, wherever the cooling tower drift is deposited. .

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IMPACTS FROM WATER DISCHARGES

The DEIS does not list water treatment chemicals to be used at the plant, and does not list any details of the toxicity of inhibitors or algicides that would be discharged. Lacking a complete discussion of the possibly pollutants in these sources's discharge, it is not possible to conclude that the this source's waste water will not contribute to water treatment problems. These chemicals could also be discharged in the cooling tower discharges. 29

SOLID WASTES

Water treatment for a large power plant can generate as much as 10 tons per month of wastes, as backwash, or filter cake. There are other waste streams, including spent catalyst, which is a hazardous waste. Catalyst wastes could be avoided by used of the SCONOX scrubber system. This generation of wastes was never described adequately in the DEIS. The materials contained in this wastes, the amount to be produced, its destiny, and its impacts on landfill capacity should all have been discussed. 30

STORMWATER RUNOFF AND SPILLS

The project will include the creation of impervious surfaces. This will cause the generation of millions of gallons of storm water runoff. This water will be tainted with oil, grease, and other contaminants present on the site and its parking lot and roof. The DEIS did not describe adequately the quality of this runoff, its destiny, and its potential impacts on nearby wetlands and surface waters. While there would be unlined detention ponds the DEIS did not describe to what degree these ponds will treat the storm water to remove pollutants before it is allowed to infiltrate into the ground water. 31

While an oil/water separator will be present, the DEIS did not assure commentors about the degree to which stormwater will be channelized through the separator. Nor did the DEIS describe the fate of wastes that are separated from the storm water. The DEIS did not describe the project's compliance with the DOE Stormwater Management rules. For instance, use of oil/water separators is actually criticized as having limited application, in DOE guidance manuals. The DEIS did not describe why a separator was appropriate for this location, or why alternative methods of storm water pollution control were not used.[6] 32

LEGIONNAIRES DISEASE

The DEIS did not provide a table of materials stored on site that listed biocides known to be effective against Legionnaires Disease. This disease breeds in moist, warm climates, including cooling towers such as those to be used by BP. It has been spread through the discharge of steam 33

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[6]Department of Ecology. Stormwater Management Manual. Chapter III-7. #91-75.

from cooling towers. In March, 2001, for instance, two Ford employees died in Ohio after exposure to Legionnaires' Disease, spread by the facility's industrial cooling towers. Legionnaires Disease organisms have also bee found in the CEGB power plant's cooling tower water, near Stafford, England. Since it is not apparent that BP plans to use appropriate chemical treatment of its cooling tower system to stifle development of the relevant bacteria, there is a threat of Legionnaires Disease from this facility. This should be discussed in a revised DEIS. 33 cont.

POWER LINE BURIAL ALTERNATIVE AND ELECTROMAGNETIC FIELDS (EMF)

The alternative of burying power lines associated with this project should have been discussed in the DEIS. Power line burial has been used at many projects, and would reduce the visual impact of these projects, and may reduce EMF exposure. EMF exposure is another potentially significant impact that was not discussed in the DEIS. 34

POWER LINE BURIAL ALTERNATIVE AND ELECTROMAGNETIC FIELDS (EMF)

This project will include a new power line. The alternative of burying power lines associated with this project should have been discussed in the DEIS. Power line burial has been used at many projects, and would reduce the visual impact of these projects, and may reduce EMF exposure, and the impacts to avian species which collide with above ground power lines.. Bird Mortality from the new power lines and EMF exposure are other potentially significant impacts that should have been discussed in the DEIS, and power line burial should be discussed as a mitigating factor, and a method of avoiding impacts on the nearby sensitive areas.

The power lines associated with this project, as currently proposed, are a potentially significant factor. The DEIS should have addressed to what degree power line burial would address this concern,.

There are many examples of burial of high voltage power lines of considerable length. Since the proposed lines are about 3000 feet long, burial of this line would reduce the visual impact of the project would protect avian species, would reduce the project's above ground "footprint," and would add only about 1/10% of one percent to the project costs; about $500,000.

Some example of actual and proposed burials of large pipeline include the 345 kV line that would be buried for 1700 feet to go under the Namekagon River near Trego, Wisconsin.

Sierra Pacific is burying a 14,000 volt line for about 2000 feet near downtown (Lake) Tahoe City, according to the company's June 9, 1999 press release.

Sierra Pacific is also burying a 120,000 volt (120kV) line for about 1700 feet near Carson City, Nevada, according to the company's April 19, 1999 press release.

Sierra Pacific's longest underground line is 2.6 miles, according to their Media Relations department.

The California Public Utility Commission's consultants, Aspen Environmental, prepared a study of an all-underground route for a 230 kV line near Pleasanton, California (Pleasanton Weekly. "Objectors, Proponents speak out on PG&E Power Line Plan." 2/16/01)

The Sumas II Power Plant has proposed a buried 230 kV line for 1.4 miles, in Abbotsford, Canada, as part of its trans-border proposal. (Canada Newswire. "NSB Receives a Revised DEIS from Sumas Energy II to Construct an International Power Line." October 2000)

The Sargent & Lundy engineering firm's advertising materials list several underground transmission lines for which they provided engineering, including a 115/138-kV line, a 230 kV line in Washington Dc, a 1800 foot 115-kV line in Baltimore, five 230-kV lines in China, two 69 kV lines in Iowa, a 1300 foot 138-kV line in Tennessee, and a one-mile, 138-kV line in Salt Lake City.

This litany of buried transmission lines indicates that this is a practicable, feasible and economic alternative design for this portion of the project. It would reduce the visual and land use impact of the project. For this reason a burial alternative, should have been presented in the DEIS.

QUESTIONS ABOUT THE EMISSIONS OFFSETS

The power plant will be permitted to emit the following annual tonnages.

NOx	239
CO	158
VOC	41
PM10	251
SO2	51

BP will purportedly shut down existing boilers, creating the following offsets:

NOx	499
CO	54
VOC	28
PM	94
SO2	7

The DEIS claimed this would have the following net impacts

NOx	-249
CO	104
VOC	13
PM	156
SO2	43

This list does not include the increased NH3 emissions of another 346 TPY. While the NH3 emissions are not a criteria pollution, it is still a toxic air emission, and an important source of secondary particulate matter, which is a criteria pollutant. Indeed, there is some evidence that 35

BP's new power plant NH3 emissions will be responsible for an increase of as much as 1400 TPY of secondary PM.

<u>DEIS DID NOT INCLUDE THE EMISSIONS INCREASES FROM THE CONTEMPORANEOUS ISOMERIZATION PROJECT</u>

This data also does not include the contemporaneous isomerization project at BP. The isomerization project will be constructed at the same time as the Cogen project, it will share the same construction lay-down yard, and in fact will share the same wetlands mitigation plan with the Cogen. The isomerization project will cause the following increases in air pollution, according to an on-line description of the project by EPA Region 10: 36

POLLUTANT	TONS/YR	DEIS CLAIMED CHANGES	NET INCREASE W/ ISOM
NOX	166	-249	-76
PM	11	156	167
SO2	84	43	127
VOC`	31	13	44
CO	47	31	78
H2SO4	2		38*
NH3			173*

*Includes totals from Table 3.2-13

<u>DEIS DID NOT ADEQUATELY DISCLOSE INFORMATION ABOUT THE PURPORTED EMISSIONS REDUCTIONS FROM THE SHUTDOWN OF THE REFINERY BOILERS</u>

ERCs must be surplus, permanent, and verifiable. The boilers that will be shut down are old, and may be shut down after the Clean Fuels project provides new boilers, so these sources would permanently emit at the levels which the DEIS claims as credits. RACT (Reasonable Available Control Technology) of BACT determinations should be made to determine realistic Emission offsets credits. Another indication that the emissions credits are not permanent is the requirement of the BP Consent Decree which mandates NOx reductions at the Cherry Point refinery. These sources may not be permitted to function at the current levels, anyway.

The DEIS also admits that new boilers will be constructed during the upcoming Clean Fuels Project. (p. 3.2-28) For this reason, the DEIS inappropriately deducted the old boilers' emissions from new cogen emissions during its discussion of the net project impacts. In other words, the old boilers' emissions are going away very soon, cogen or no cogen. The DEIS needed to discuss the emissions from the new Clean Fuel boilers, as the only proper, legitimate offsetting emissions reductions that could be deducted from the new Cogen emissions. Since the DEIS failed to consider the permitted emissions from the boilers that are about to be constructed, the DEIS's claims of new air quality benefits are misleading and untrue. 37

Emission reduction credit guidance from the EPA (cited later in this document) generally suggests that the low value of actual emissions, vs. permitted emissions should be employed to determine the appropriate ERC. But the DEIS does not say if the figures given for the boiler emissions were permitted or actual emissions.

DEIS DID NOT DISCUSS THE NOX REDUCTIONS MANDATED UNDER THE BP CONSENT DECREE

Furthermore, BP is under the strictures of a Consent Decree with the Federal EPA, under which BP is required to reduce its NOx emissions at the majority of its heaters and other equipment at the Cherry Point Refinery. The Consent Decree also set limits on how BP can characterize NOx emissions reductions from equipment subject to the Consent Decree. The DEIS did not discuss the relationship between the NOx reductions required under the consent decree, and the NOx reductions from shutdown of the utility boilers, that is discussed in the DEIS.

This discussion should be required in the DEIS because ERCs must be surplus, quantifiable and permanent. If the old boilers were not shut down, it is doubtful that the old boiler emissions would have continued permanently at their current rate, because at some point RACT would have been mandated. Thus the boilers' emissions above RACT levels are not surplus, because some reductions will soon be required by law. 37 cont.

Permanent ERCs should not be based on past, high, emission rates, since those rates will not continue indefinitely, due to imposition of RACT, and the requirements of the Consent Decree, among other factors.

Federal register discussions state that VOC sources can be considered to impact ozone non-attainment areas within 36 hours wind travel time, because precursor emissions that occur within 36 hours traveltime of each other interact to form oxidant.[1]

Based on these discussions, The commentors ask that the old boilers at BP can be considered to contribute to the recent non-attainment status of the Seattle and Vancouver BC areas. EPA policy discussions suggest that RACT emission rates should be considered, rather than actual emission rates, or whichever is lower, for sources that are in non-attainment areas.[2]

The commentors are also concerned that several other criteria be followed in determining an acceptable amount of ERCs from the old boiler shutdown. The DEIS should establish that the Washington SIP does not already include, as part of its attainment plans, emissions reductions from shutdowns and the phasing out of aged emission units.

Some SIPs assume a quantity of reductions from new plant openings and existing plant shutdowns. These SIPs incorporate into their attainment strategy a net "turnover" reduction in emissions because new plants will be cleaner than the old shutdown plants.

If the Washington SIP includes this sort of "turnover" emissions reduction as part of an implementation strategy, then ERCs from the shutdown of the old BP boilers should not be granted, otherwise those emissions reductions would be double counted. (Federal Register 4/7/82, p. 15081)

In addition, if the Washington SIP contains emissions limits for the BP old boilers that are lower than BP's computation of its ERCs, then the SIP limits should be used to compute ERCs instead. (Federal Register, 1/16/79, p. 3284)

In summary, the old boiler actual emission rates should be compared with RACT/BACT emission rates from similar units, and the lower of those two rates should be used in the DEIS discussion of emissions reductions from the old boilers' shutdown.

<u>**AIR TOXICS**</u>

The new cogen project will emit several highly hazardous air toxics, including benzene and formaldehyde, and others, which are listed at Table 3.2-13. Toxics such as Acrolien, (and several metals), are emitted at amounts exceeding the Small Quantity Emissions Rate for both the hourly and annual emissions rate. But the DEIS fails to describe whether the project will result in greater or lesser emissions of these and other air toxics. The DEIS does not compare the emissions of air toxics from the cogen project, with the purported "reductions" caused by the shut down of the older utility boilers. 38

The DEIS should have performed this comparison. It is not wise or legal to trade increases in comparatively hazardous air pollutants for decreases in relatively less harmful pollutants. Such a trade should be fully disclosed and discussed on an DEIS. As one treatise on this topic stated:

> "Certainly no one should be allowed to trade an increase in a more harmful pollutant for a decrease in a more benign one simply because it is cheaper to do so...if an increase in a hazardous pollutant were to be traded for a decrease in a more benign one the net effect would be a greater threat to public health despite the equivalence in pollutant quantities" [3]

But the trade-off of some decreases in NOx emissions from the old boilers, for increased emissions in formaldehyde and benzene emissions and other VOCs and air toxics from the BP Cogen, is a trade of comparatively benign pollutants for more harmful pollutants. In particular, benzene increases as a trade for reduction of generic emissions are explicitly prohibited.

EPA guidance documents regarding pollution trades and reductions clearly and plainly state:

> "(E)ven within a category (such as VOCs), pollutants that pose significant health hazards cannot be traded against less harmful pollutants ... The emissions of ...<u>benzene</u> which (is) listed under section 112, may be increased at one emission point ... <u>only as long as there is a compensating decrease</u> in the emission of the same pollutants at another emission point at the same location or a contiguous location ... Sources may equally trade

> hazardous pollutants with nonhazardous pollutants in the same criteria pollutant category only in the cases where the source decreases the emission of the hazardous pollutant.(emphasis and parentheses comment added) [4]

A later update of this guidance document continued to maintain the ban on trades of hazardous for non-hazardous pollutants, and specifically proscribed trades involving increases in benzene emissions:

> "Emissions Trades Should Not Increase Hazardous Pollutants. Where pollutants have been listed under Section 112, but are not yet subject to specific regulations...states may allow trades consisting of equivalent increases and decreases of the same listed pollutant ... the State may also approve trades in which reductions of hazardous pollutants compensate for increases in non-hazardous pollutants....a source may trade benzene for any non-hazardous VOC, if the benzene emissions are decreased." [5]

This coverage of this quotation would also apply both to formaldehyde, which was listed under Section 112 as part of the Clean Air act amendments of 1990, and to benzene, which was listed at an earlier time under Section 112. Language in the amended Section 112 also addresses trades of hazardous pollutants as follows;

> "A physical change in ... a major source which results in a greater than de minimis increase in actual emissions of a hazardous air pollutant ... will be offset by an equal or greater decrease in ... emissions of another hazardous air pollutant ... which is deemed more hazardous." [6]

CONCLUSIONS

ERCs from the old boilers shutdown should be limited to the RACT emissions from these boilers, or the actual boiler emissions, or the emissions of the Clean Fuel Project replacement boiler, whichever is lower. If these boilers are supposed to be shut down or controlled under the Consent Decree, those reductions should not be considered credits at all. Reductions in non-toxic air emissions should not be described as offsetting increased emissions of air toxics. If air toxic emissions will actually rise, the DEIS should say so and provide details.

ENDNOTES

1.Federal Register, Vol. 44, No. 11, January 16, 1969. P. 3278- 9.

2. Federal Register, 4/7/82, p. 15080.

3. Landau, Jack. "Economic Dream or Environmental Nightmare? The Legality of the "Bubble Concept" in Air and Water Pollution Control." Environmental Affairs. Vol. 8:705, pp. 770 and 780.)

4. Federal Register Vol. 44, No. 239, December 11, 1979, page 71784.

5. Federal Register, Vol. 47, No. 67, April 7, 1982, pp. 15082-3.

6.Public Law 101-548, Nov. 15, 1990, 104 Stat.2544.,Section 112, (g)(1)(A).

EXHIBITS REGARDING UREA AND AIR COOLING

AMMONIA / UREA

New fuel-cell projects are launched in Europe

At the *Seventh Annual Grove Fuel Cell Symposium* in London last fall, FuelCell Energy Inc, Danbury, Conn, announced that it will deliver seven new fuel-cell powerplants to various European countries. The 250-kW units will be based on the company's Direct FuelCell technology, which eliminates external fuel processing to extract hydrogen from a hydrocarbon fuel.

Most fuel cells require an external reforming device to produce hydrogen for the stack, but in the Direct FuelCell, the fuel is fed directly to the stack with no external reforming. While natural gas typically is the primary fuel, any hydrogen-rich gas—including gas from landfills, wastewater treatment anaerobic digesters, coal mines, or liquid fuel—could be used with appropriate cleanup, the developer says. A 250-kW Direct FuelCell at the manufacturer's Connecticut headquarters began powering building loads in 1999. The new European installations include:

- RWE—Heat and power at an energy park.
- IZAR—Energy for this ship-building company.
- Deutsche Telecom—Direct-current backup power for a telecommunications center.
- EnBW/Michelin—Electricity and process steam for a tire-manufacturing plant.
- E-on/Degussa—Generation of power, heat, and CO_2 gas for industrial use.
- IPF KG—Backup power and cogeneration for the Otto-v-Guericke University Medical Institute.
- VSE AG—Cogeneration for industrial laundry and CO_2 use for greenhouse fertilization.

"We are pleased to add these orders to our existing backlog as we continue to ramp-up our manufacturing capability to commercialization," says Jerry D Leitman, president and CEO of FuelCell Energy.

Readers talk back!

Urea-to-ammonia experience wider than reported

I read with interest your article titled "DeNO$_x$ systems detox plant exhaust," (September/October 2001, p 69). Unfortunately, your readers might be led to believe that Hamon Research-Cottrell's U2A process is the only urea-to-ammonia conversion process available in the market. Not only is that not the case, but the AOD process offered by Environmental Elements Corp (EEC), Baltimore, Md, is the more advanced and more widely applied technology for producing ammonia from urea.

EEC has two full years of operating experience at Mirant Co's Canal station, and one full season of operation at AEP's Gavin plant, a total of over 3000 MW on which we have actual operating history. Further, EEC has on order an additional 9000 MW of AOD systems for application to several more AEP plants.

Hamilton Walker Jr
Manager, Applications Engineering
Environmental Elements Corp
Baltimore, Md

Something old, something new . . .

Pretty good Marmy story in the [November/December 2001] issue [p 26], but some education might be in order. How many of your readers have any idea what is meant by the "Ringelmann No. 5 cigar"? I suspect that only those over 70 in age—or maybe over 60—would have a clue. No, it's not a Cuban by the name of Ringelmann.

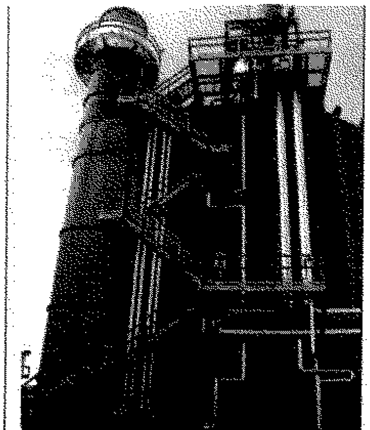
Also, I enjoyed the short news item, p 14, on the large powerplant for China. I [am familiar with] supercritical steam cycles, but what, pray tell, is the "spiral-wound furnace configuration?" If there has been a description of this technology in the magazine, I have missed it. Can you reference an issue in which this is described?

R H Bernstein, PE
Dayton, Ohio

Editor's note: *The brand name of Marmy's cigars reveals our industry's progress in environmental stewardship. The Ringelmann Smoke Chart was until the 1970s the method for determining if stack emissions were within regulatory limits. The chart, developed by a French professor, Maximilian Ringelmann, was simply a series of cards with graduated shades of gray, varying by five equal steps between all white (Card 0) and all black (Card 5).*

A regulatory inspector merely compared the color on the permitted card, say, Card 3, to the color of the smoke emanating from the stack—the apparent darkness or opacity of the plume indicating the concentration and size of particulate emissions. Of course, Marmaduke smokes the richest, strongest cigars, Ringelmann No. 5s.

For information on the spiral-wound supercritical furnace, see story on the Haramachi station (Power, July/August 2001, p 87).



Installation and Start-up of the First Large Scale AOD™ Process on two 1,300 MW Coal-Fired Midwest Utility Boilers

Hamilton G. Walker, Jr. Director, Marketing and Sales, AOD™ Business, EEC.
Jeffrey J. Prickel, AOD™ Business Unit Manager, EEC

Summary:

Recent Federal EPA regulations require power plants to plan for substantial reductions in their emissions of nitrogen oxides (NO_x). The most widely used technology for high efficiency reduction of NO_x is Selective Catalytic Reduction (SCR) using ammonia as the reducing agent. To achieve high levels of NO_x reduction in a large coal-fired power plant, ammonia consumption of several thousands of pounds per hour is typical. There are two traditional forms of ammonia used for this purpose; anhydrous and aqueous ammonia. The potential for an accidental release of a large quantity of anhydrous ammonia poses a safety risk to plant workers and the surrounding communities. Moreover, the use of anhydrous ammonia is heavily regulated by both OSHA and EPA, and compliance with these regulations may require additional plant staff or the use of outside consultants. The use of aqueous ammonia requires the transportation and storage of much larger quantities of diluted reagent and adds operating cost in the form of energy to evaporate the water of solution.

Ammonia On Demand (AOD™), an alternative to the use of anhydrous or aqueous ammonia, has been developed and implemented over the past year. Environmental Elements Corporation (EEC) has obtained a license to technology jointly owned by SiirTec Nigi of Milan, Italy and HERA LLC of Lake Forest, CA for the production of ammonia from solid urea. The AOD™ process was first installed at the Canal Station of Mirant Corporation in Massachusetts and operated successfully during the summer of 2000. Rather than transport and store anhydrous or aqueous ammonia, this site trucks in solid urea and stores the benign chemical in silos on site.

The AOD™ process begins with solid urea granules or prill, and creates a solution by dissolving the urea in recycled solution. This solution is then pumped through an economizer to the hydrolyzer. In the hydrolyzer, the solution is heated to reaction temperature and the urea reacts with water to form ammonia and carbon dioxide. Steam is fed into the bottom of the hydrolyzer to strip the dissolved ammonia from solution and transport it to the ammonia injection grid of the SCR. The ammonia stream may be diluted with warm air to reduce the concentration to 5% or less as desired by the SCR manufacturer. The entire process is automatically controlled to respond rapidly to changes in demand from the SCR control system.

This technology has recently been applied to two 1,300 MW coal fired located in Cheshire, Ohio. The boilers will have a total of six SCRs on both units. The system was originally planned to use anhydrous ammonia, but was changed to a urea-based ammonia system in response to concerns expressed by the local townspeople. The order for an AOD™ system to supply both boilers was given to EEC in December, 2000, and delivery of the process equipment was completed in April. The system was placed into commercial operation in May. The design capacity is 7,000 lbs/hr of ammonia.

Mr. Al Mann
April 24, 2001
Page 2

The AOD™ system was started up without serious complications, and has entered the testing phase to prove performance prior to acceptance. Preliminary results indicate it is operating smoothly and producing the required levels of ammonia. Utility consumption is as predicted, and response time is more than adequate to match changes in boiler load.

The major advantage of the AOD™ process is its ability to produce ammonia on site at reasonable cost and in response to the demands of the plant without the necessity of storing or handling hazardous materials, creating a safer environment for plant staff and the local community.

Wednesday, October 02, 2002

Urea-based SCR technology achieves 12 ppm NOx on natural gas engine

By Ravi Krishnan, RJM Corp.

Oct. 1, 2002 – RJM's ARIS SCR technology recently achieved a 95.9 percent NOx reduction on a 320 kW lean burn natural gas engine.

The system was installed at the corporate headquarters of Clean Air Partners located in San Diego, California, a locale subject to some of the nation's most stringent air quality regulations.

ARIS, which stands for advanced reagent injection system, meters precise amounts of a safe, easy-to-use reagent into the exhaust stream of diesel or lean-burn natural gas. Once in the exhaust, the reagent decomposes and forms ammonia, which passes over a catalyst to turn ozone-forming oxides of nitrogen (NOx) into water, nitrogen and CO2.

The system was delivered and installed on the natural gas engine at Clean Air Partners in less than two months and achieved a 95.9 percent reduction, resulting in a final NOx emission rate of 12 ppm. The unit was tested at an outside temperature of 60 F, and produced an exhaust temperature of 968 F. The high temperature catalyst used in the system operates up to a temperature of 1,022 F.

The calculated urea consumption for the engine when operating at 98.5 percent load was approximately 0.38 gallons/hour. At a urea cost of $1.25/gallon (bulk delivery) and assuming 4,000 hours of annual operation, total urea consumption cost is less than $1,900 per year. Urea consumption for natural gas engines is considerably lower than that of diesel engines because of the lower baseline NOx emissions associated with natural gas engines.

Total annualized cost of the system is estimated at $3,846 per ton of NOx removed at 4,000 hours of operation. The ARIS system becomes more attractive at 8,000 hours of operation, with annual cost/ton estimates of NOx removed at $2,205.

Such compliance cost estimates are exceptionally attractive for a natural gas engine, which have lower baseline NOx emissions (and therefore lower NOx tonnage reduction potential when compared to diesel) besides lower additive (urea) cost.

Moreover, as the rated capacity of engines increase, the relative cost of compliance is lower due to the fixed nature of hardware and catalyst cost. Exhibit 1 (below)compares the cost of compliance for the 320 kW natural gas engine at 4,000 hours and 8,000 hours of operation.

NO_x Compliance Costs for SCR on Natural Gas Engines (Exhibit I)		
Annualized Operating Costs	4000 Hours of Operation	8000 Hours of Operation
1. Capital Cost Recovery - Hardware	$ 3,648	$ 3,648
2. Capital Cost Recovery - Catalyst	$ 7,544	$ 7,544
3. Variable Operating Costs	$ 1,892	$ 3,704
4. Fixed Operating Costs		
Total Annual Costs	$ 12,884	$ 14,366
Total Tons of NO_x Removed	3.35	4.70
Annual Cost/Ton of NO_x Removed	$3,846	$3,205
Source: KJM		

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AEP ANNOUNCES PLANS TO USE UREA-BASED SYSTEM TO REDUCE NITROGEN OXIDE EMISSIONS AT GAVIN PLANT

COLUMBUS, Ohio, Dec. 18, 2000 -- Following an extensive engineering and technical review, and aided by recent technological developments, American Electric **Power** (NYSE: AEP) is changing the design of the selective catalytic reduction (SCR) system it will install at its Gen. James M. Gavin Plant at Cheshire, Ohio.

Company officials announced plans to employ a **urea**-based system as the source of ammonia for the plant's SCR system, which will begin operation in the spring of 2001. Previously, the company had announced that anhydrous ammonia would be used in the SCR system to achieve the reductions in nitrogen oxide (NOx) emissions that are being required by the U.S. Environmental Protection Agency.

"Our neighbors in and around Cheshire told us they were very concerned about the impact of a serious accident involving a major release of anhydrous ammonia due to their close proximity to the plant," said John Norris, AEP's senior vice president of operations and technical services.

"We took those concerns to heart," Norris said. " Safety is a primary concern in everything we do. We've spent considerable effort reviewing our original analysis and seeking new information to see if we could find another way to meet our emission reduction obligations and address the community's concerns at the same time. We have found a solution that meets both of these needs."

Norris said that the decision represents a significant commitment on AEP's part. While the switch to a **urea** system will increase both the construction and the operating costs of the plant over its remaining life, it will also eliminate the need to store large amounts of anhydrous ammonia at the plant. Norris emphasized that health and safety issues were taking precedence over cost considerations.

The announcement came at a community forum arranged by the company at River Valley High School, near Cheshire. The meeting was a follow-up to an earlier forum where area residents raised objections to the proposed **use** of anhydrous ammonia.

Duane Phlegar, general manager of Gavin Plant, explained that the company values its relationship with the local community. "The **urea**-based system will eliminate concerns about the transportation and storage of anhydrous ammonia at the plant," he said.

The SCR system uses a chemical reaction to break down NOx present in the exhaust gases that are released during the coal combustion process. Ammonia is added to the flue gases, which are then channeled through a catalyst that breaks down the gases into elemental nitrogen and water. AEP and other **power** generators in the Midwest and Southeast are required by federal mandate to reduce their NOx emissions by May 2003.

A **urea**-based system does not involve the storage of anhydrous ammonia at the plant site. Instead, **urea** -- a dry, granular or pelleted nitrogen fertilizer -- will be converted to ammonia just prior to the point at which it is injected into the plant's exhaust gases. Storage of **urea** in its dry, granular form does not pose any extraordinary handling challenges or potential health hazards that require the development of emergency response plans.

Phlegar explained that AEP plans to utilize an expedited project management schedule in order to engineer, design and install the urea-based system for both units at Gavin Plant in time for the 2001 ozone season (May through September). Since urea-based technology has never been tested or installed on a power plant of Gavin's size, however, he noted that the plant may encounter some start-up challenges when the SCR system begins full-scale operation. He expressed confidence, however, that the company can engineer a successful urea system for Gavin Plant. The Gavin Plant consists of two 1300-megawatt coal-fired generating units and is the largest generating station in Ohio.

Norris stated that the company conducted a comprehensive evaluation, including the possible use of aqueous ammonia -- a less concentrated form of ammonia -- for the SCR system.

"We recognize that nearly three months have elapsed since we held our first community forum," Phlegar said. "To put it simply, conducting these detailed studies and evaluating all of the possible alternatives took longer than we originally anticipated. A urea-based SCR system has been installed only very recently in two power plants in the entire country, and those units are much smaller than the Gavin units. It took a great deal of study before we were able to conclude that we can take this technology and scale it up successfully to a plant of Gavin's size."

American Electric Power is a multinational energy company based in Columbus, Ohio. AEP is one of the United States' largest generators of electricity with more than 38,000 megawatts of generating capacity. AEP is also one of the nation's leading wholesale energy marketers and traders. AEP delivers electricity to more than 4.8 million customers in 11 states -- Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. The company serves more than 4 million customers outside the U.S. through holdings in Australia, Brazil, China, Mexico and the United Kingdom. Wholly owned subsidiaries are involved in power engineering, construction, energy management and telecommunications services.

News releases and other information about AEP can be found on the World Wide Web at http://www.aep.com.

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American Electric Power
614/223-1620

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Monday, July 29, 2002

Wahlco awarded $1 million contract for urea-to-ammonia conversion systems

SANTA ANA, Calif., July 23, 2002 -- Wahlco Inc. announced the award of a $1 million contract to provide the patented U2A ™ (urea-to-ammonia conversion) system to be used in NOx reduction applications at a major Maryland installation.

Designed to produce 100 lb/hr of ammonia from a 50% urea solution for year-round operation, the system will serve three gas fired turbines at a liquid natural gas compressor station near Baltimore.

Ammonia is used in reducing the emission of toxic NOx (oxides of nitrogen) into the atmosphere. However, ammonia is regulated and considered a hazardous substance by the EPA and OSHA. The U2A system safely converts urea, a stable compound commonly used in fertilizer, into ammonia as needed, thereby eliminating transportation and storage risks.

"We're all aware of heightened sensitivity surrounding public safety issues," stated James Clark, president and CEO of Wahlco. "When weighing the risks of handling ammonia, there are compelling reasons to consider alternatives. We predict strong future demand for U2A system technology which enjoys a proven track record for reliability and safety."

Developed by EC&C Technologies, under a grant sponsorship from the EPA's SBIR program, Wahlco shares the exclusive license to supply the patented U2A system worldwide with Hamon Research-Cottrell. Wahlco and Hamon are currently working with seven utilities at nine locations, totaling approximately 12,000 Megawatts of generating power, who have chosen U2A equipment for their NOx systems.

Founded in 1972, Wahlco designs and manufactures air pollution control systems including flue gas conditioning equipment, anhydrous and aqueous ammonia systems and U2A urea-to-ammonia conversion systems for energy utilities, refineries and industrial clients.

Wahlco (formerly Wahlco Environmental Systems) is privately held and was purchased by members of the management team in partnership with industry professionals in January of 2001. Located in Santa Ana, Wahlco is not affiliated with Wahlco Engineered Products Inc. or Wahlco Metroflex.

For further information on Wahlco and/or U2A ™ System technology, visit www.wahlco.com.

EEC ENVIRONMENTAL ELEMENTS CORPORATION

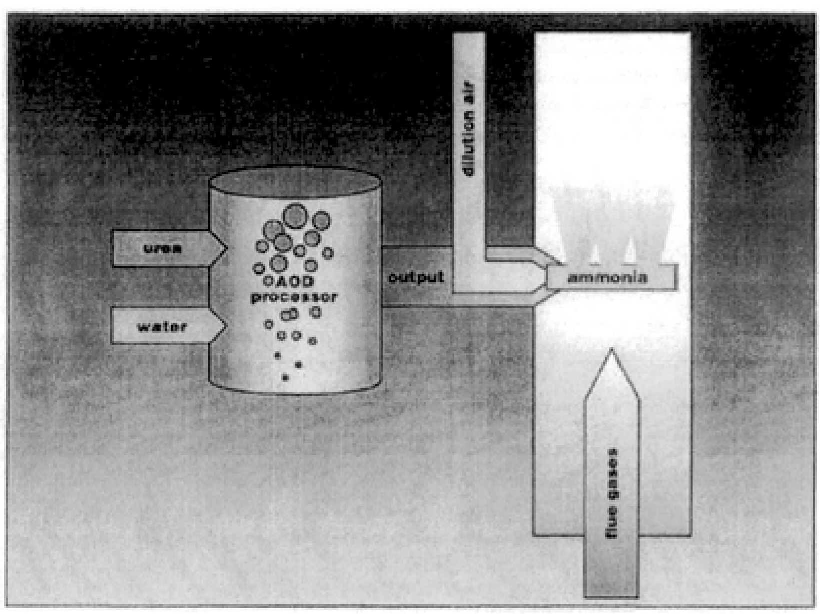
LEADING TECHN INNOVATIVE SOLUTI

Ammonia Delivery Systems

General Description

EEC provides several products and services aimed at reducing NOx emissions, which are stringently r air quality agencies worldwide, primarily for the power generation markets. We are the exclusive prov patented Ammonia-on-Demand (AOD™) technology, a safer alternative to more traditional ammonia systems for SCR applications. We have also expanded our product offering to include anhydrous and reagent delivery systems as well as gas turbine SCR's through an alliance we've formed with Peerless one of the market leaders in the gas turbine NOx market.

Capabilities



Ammonia on Demand

Our AOD™ process supplies ammonia to SCR, SNCR or flue gas conditioning systems without the s environmental risks associated with the storage of large quantities of anhydrous or aqueous ammonia. utilizes a safe, environmentally benign urea to create ammonia only as needed. The system is a compa mounted, modular and self-contained chemical plant that produces ammonia on-site and on-demand i coordination with the specific demand requirements of the SCR. The principal benefits include the eli the need to transport, store and handle large quantities of a hazardous chemical and the reduction of ri operating personnel and to the neighboring community. The need to follow cumbersome and costly re requirements for risk management and emergency response is also eliminated with AOD™.

In addition to its use in SCR systems, ammonia has other pollution control applications in which the process can be of significant benefit.

- Injection of ammonia to condition flue gasses to assist in the removal of fly ash
- Injection of ammonia as a means of controlling sulfur oxides, the origin of the so-called "blue p
- Ammonia-based SNCR systems
- SCR systems in combined-cycle combustion turbines

The first commercial application of our AOD™ technology began operation in September, 2000 at a p in Sandwich, Massachusetts operated by Mirant Corporation, formerly Southern Energy, Inc.

Anhydrous and Aqueous systems

These products, manufactured by our alliance partner, are ammonia unloading, storage and vaporizati Each one is backed by proven expertise ranging from the storage, handing and transfer equipment, to t vaporization, dilution, control and injection systems.

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Regional Service Centers

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Location: Richmond, Virginia
Contact: Stan Elam
Phone: 804-843-3626

Mid-south
Location: Marshall, Texas
Contact: Lloyd Curry

Phone: 903-938-8937

Southeast
Location: Pensacola, Florida
Contact: Gary Phillips
Phone: 850-683-4500

Midwest
Location: Milwaukee, Wisconsin
Contact: Anthony Pons
Phone: 262-243-9097

Worldwide Response
(Outside regional centers)
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Alliances (Click to learn more)

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- Hybrid Systems SCR/SNCR
- Urea-to-Ammonia Process

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) reduces NOx emissions from boiler flue gases by introducing a reagent - ammonia - upstream of a catalyst bed. The reagent, in the presence of the catalyst (typically Vanadium Petoxide) reacts with the NOx to conver to harmless by-products. Reactions take place in the range of 500 F to 800F (260C t 425C) which is typically found downstream of the economizer on a boiler. Poper ammonia mixing within given space constraints is a very important design consideration.

- Gas turbines
- High and low dust
- Tail end

Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction is a post-combustion technology that is designed t control NOx emissions from boilers. The process works by injecting a reagent (ammo or urea) into the radiant and convection regions of a furnace to treat the flue gases after full combustion has taken place. Specifically designed injectors distribute the reagent (ammonia or urea) throughout the flue gases at the narrow temperature ran of 1600F to 2100F (870C to 1150C.) Boiler temperature mapping is critical to determining injector probe placement.

- Urea based technology
- Ammonia technology

Hybrid Systems SCR/SNCR

Hybrid systems combine both the technologies of Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). Both boiler injectors and a catalyst system are utilized in tandem with the benefits of high NOx removal reduction, low catalyst volume required resulting in low capital cost, less real estate required, easie retrofit, and greatest flexibility and room for expansion. Unlike other suppliers, Hamo air pollution control division provides equipment and full turnkey capabilities in both SCR systems and ammonia and urea SNCR systems. Thus, our expertise allows us to optimize the selection of an SNCR, SCR, or a hybrid system for your unique applicait

Urea-to-Ammonia Process

Both urea and ammonia are suitable for SNCR systems, while only ammonia is neede for SCR systems. Both anhydrous and aqueous ammonia have been classified by the EPA as a regulated toxic substance. Hazards from exposure vary from minor discomf to toxic poisoning. Therefore, ammonia restrictions, or even prohibition in some area have been placed by local authorities. To counter this risk, Hamon offers a patented Onsite Urea-to-Ammonia Generation System, U2Atm, that produces ammonia by a method that avoids the hazards of its transportation, trasfew, and storage. For this process, dry urea is mixed with water to form an aqueous solution that is fed to an i line reactor at a rate to produce the required ammonia. Heat is applied to carry out t generation under controlled conditions to maintain a constant ammonia gas supply pressure. The process produces the required ammonia mixture, which requres no storage except for the small amount in the reactor.

AIR

COOLING

NEW TECHNOLOGY

Are fuel cells heir apparent to the gas turbine?

By **Jason Makansi,** Executive Editor

If the gas turbine reigns supreme as the prime mover of choice for power generation today, then the fuel cell is considered by some to be the prince and heir to the throne. And, depending on your assessment of the technology's status, you may regard the prince as an infant or adolescent. Either way, though, it seems fairly clear that the king isn't going to die or be dethroned anytime soon.

Unlike other advanced technologies—such as renewables—fuel cells are more inclusive of conventional players in power generation. For example, they involve a source of fuel; thus, natural-gas and coal interests can support the technology. Cogeneration can make sense for high-temperature fuel cells; thus, industrial concerns have a stake in the technology. Finally, no regional limitation exists—such as the availability of renewable resources—so the technology does not split electric-utility support; urban utilities see as much promise as rural, eastern utilities as much as western, and so on. Overseas support is high as well, with Japan making a formidable challenge to US technology development.

While the base of support is broad, the technology has a long way to go—at least as a central-station option. One reason for optimism on the part of developers, though, is that this is no longer the primary path to commercialization. Distributed generation—the concept of locating small increments of power very close to load centers—is the near-term now sought by developers.

Technology status

For electric generation, three basic fuel-cell options—defined by the electrolyte used and generally characterized by operating temperature—are under vigorous development: phosphoric-acid (PA), molten-carbonate (MC), and solid-oxide (SO). Basic technology for these three options has been described previously (POWER, May 1990, p 82; September 1991, p 70). In the early to mid 1980s, Consolidated Edison Co of New York Inc and Tokyo Electric Power Co (Tepco) both demonstrated nominal 4.5-MW PA systems.

For PA technology, the highest commercial achievement, based on unit capacity, is embodied by the 11-MW facility operating at Tepco's Goi station, which followed the 4.5-MW demo. MC technology will be demonstrated at the 2-MW scale in Santa Clara, Calif (Fig 1). Groundbreaking for the Santa Clara facility occurred in April with initial operation expected in early 1995. This effort was preceded by the operation of a 100-kW MC unit by Pacific Gas & Electric Co. A 100-kW SO unit has been fabricated, with installation expected soon, and operation by Southern California Gas Co is scheduled for later this year. Two 20-kW SO units have been operating in Japan; one has logged over 6500 hours.

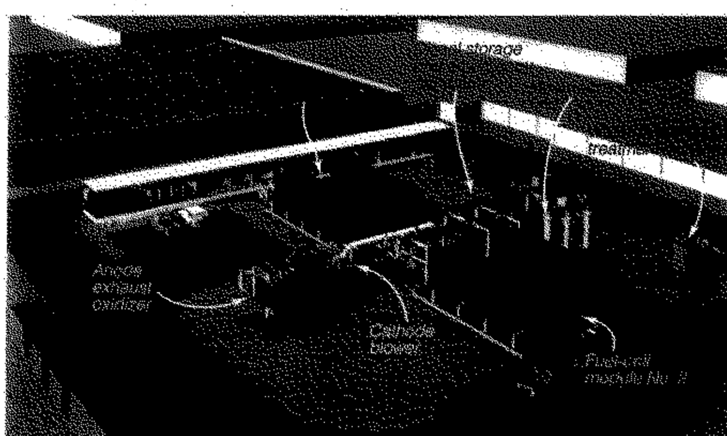
Many experts regard the PA technology to be fully commercial in smaller units. All that is needed is the production volume to lower manufacturing costs. As an example, a 200-kW PA unit, one of 25 demonstrations in operation or on order, came on-line in August last year at the Pittsburgh (Pa) International Airport (Fig 2). Reported cost was $2900/kW. The demonstration is sponsored by Consolidated Natural Gas Co, Pittsburgh; Duquesne Light Co; EPRI; and the Pennsylvania Energy Office.

DOE reported last year that current fuel cell demonstrations under way or planned, including all technologies, amounted to 50 MW worldwide. Almost all of the operating facilities are based on PA technology in facilities built up from 25- and 200-MW modular units. Of these, a facility in Japan reported in mid 1993 that it had passed the 5000-hr continuous operation mark, described as a first for a commercial unit.

Packaging of fuel-cell powerplants has garnered the interest of at least one firm. Stewart & Stevenson Co (S&S), Houston, Tex, best known as a packager of gas-turbine power generating units, has provided package design (Fig 3) for MC units under an agreement with Bechtel Corp, San Francisco, Calif, and M-C Power Corp, Burr Ridge, Ill. Two 250-kW "proof-of-concept" units have been packaged and installed at a Union Oil of California site and at Kaiser Permanente Hospital in San Diego, Calif. S&S's interest in fuel cells is based on its long history of packaging gas turbines. With so many similarities between the two technologies, S&S views it as a logical extension of that business.

Auxiliary systems critical

Fuel-cell powerplants involve key auxiliary systems which are not necessarily proven technology in themselves. The fuel is first processed, or reformed, into hydrogen in an upstream section of the plant. Methane reforming is a basic, well-known unit operation that involves passing natural gas over a catalyst at 1600F or so, and may be followed by what's called a shift converter that converts some of the reaction products to hydrogen, using steam. This fuel processing step can be integrated into



1. Two 1-MW modules comprise the Santa Clara demonstration facility now under construction, characterized by an expected 50% net electrical efficiency, 1.8 MW net power output

Environmental management

Profit from latest experience with air-cooled condensers

The project design and development benefits of this technology are clear. But plant operators must understand and prepare for seasonal challenges, among others, if it is to continue being a long-term performance asset

By Robert Swanekamp, PE, Associate Editor

Air-cooled (AC) condenser technology was developed in Europe over 30 years ago, when water availability became a major issue. Today, AC technology still enjoys extensive use overseas. South Africa, for example, lays claim to the world's largest AC condenser at the 4000-MW Matimba power station, and nationwide has an estimated 10,000 MW of capacity using AC technology. In the past several years, the US also has seen a rapid rise in the application of the technology. To illustrate: One leading manufacturer sold only five AC systems to the North American market throughout the 1960s and 1970s. In the 1980s and early 1990s, the firm has already sold 38 systems.

Positive project design and development aspects notwithstanding, (box p 80), AC condensers introduce several operations and maintenance (O&M) and performance challenges. Inability to hold condenser vacuum during hot weather can significantly lower plant efficiency and capacity and may even lead to forced outages. When summer ends and winter blows in, freezing problems can shut down a fully loaded plant within hours, and, if tubes are ruptured, can keep the plant down for weeks. Mechanical and electrical problems might also be introduced by the massive size or sheer number of fans and gear boxes. Even if the system is running well, AC condensers may exact an O&M toll in cleaning heat-exchanger surfaces or monitoring air leakage into the condenser tubes. Both the performance and the O&M challenges can have a particularly significant impact on peaking-type facilities.

Don't like hot weather

At elevated ambient temperatures, AC condensers cannot produce the high vacuum required to maximize steam-turbine output, thus lowering cycle efficiency and net plant capacity. Several plant managers report their facilities lose as much as one-third of the capacity during the heat of a summer day.

One of the largest AC condensers in the US is located at the Doswell LP plant in Virginia, which is owned by Diamond Energy Inc, Los Angeles, Calif. According to Jay Sohi, director of engineering and project management for Diamond, manufacturer's performance curves are now being updated based on the plant's first two summer operating seasons to quantify the actual relationship between ambient temperature and plant capacity. Until the curves are ready, the exact amount of capacity loss is not known, but Sohi reports the relationship is "worse than linear." The plant meets its design specification of 605 MW at 90F, but experiences a rapid decrease at ambient temperatures above that.

According to Randy Peterson, project manager for UC Operating Services, Columbia, Md, the Rosebud powerplant, Colstrip, Mont, begins to experience a drop in capacity attributed to its AC condenser when ambient temperature exceeds 75F.

Air recirculation looms large

Perhaps the most dramatic reported effects of hot weather on AC condensers have been experienced at the Matimba station, owned and operated by Eskom, the South African state utility. Like the systems prevalent in the US, the Matimba AC condenser is a direct-acting, dry-cooled type. According to an Eskom engineering investigation by H B Goldschagg, Matim-

1. Unique A-frame design of Camarillo's air-cooled condenser maximizes heat-transfer surface area while minimizing space requirements ba's exceptionally large size and six-in-line condenser configuration fosters substantial recirculation of the hot air plume during certain wind and temperature conditions.

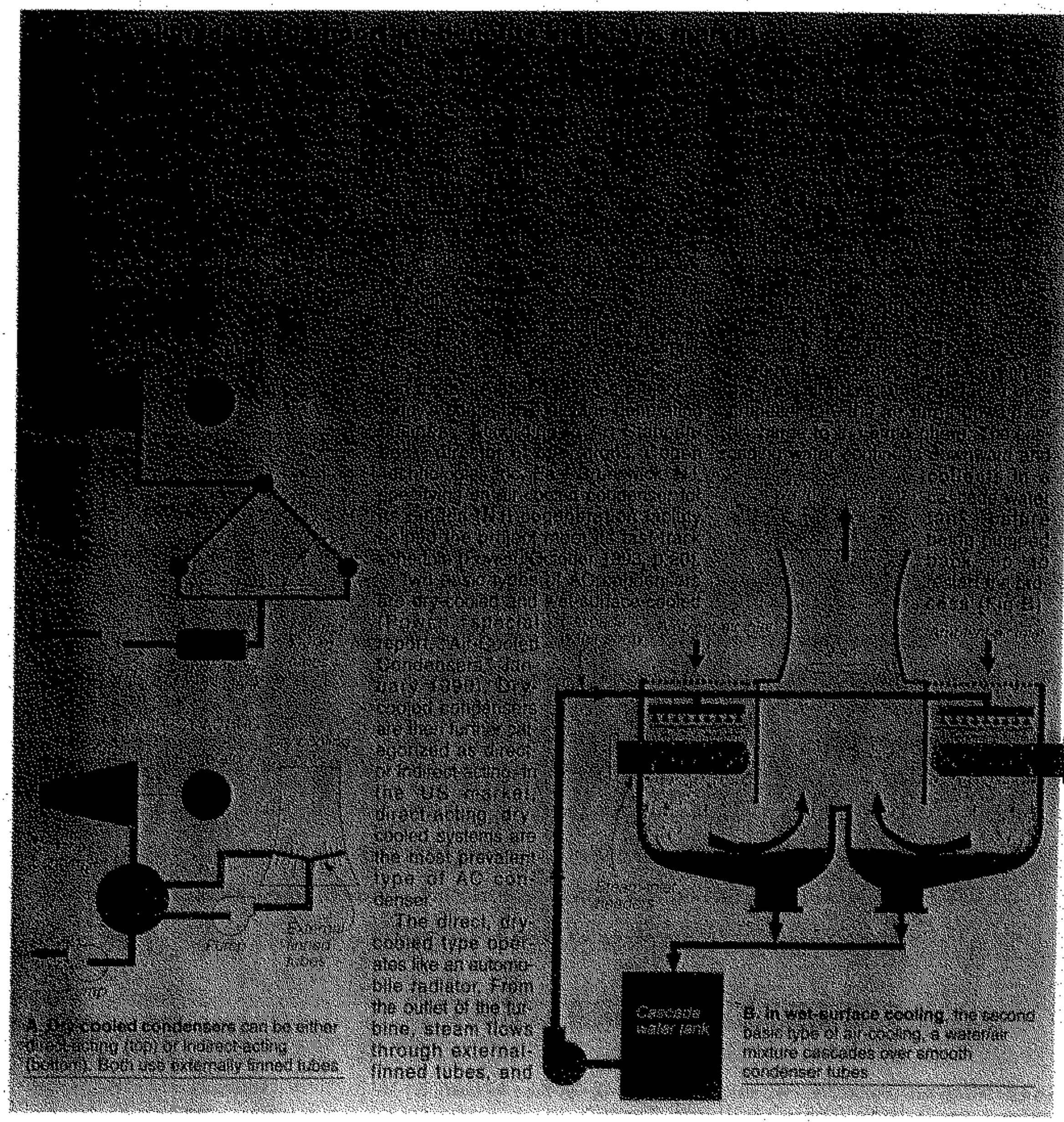
When winds blow from the west, the hot air plume discharged from the condenser slumps over the eastern air-inlet side, and is drawn back into the condenser by the cooling air fans. The recirculated hot air causes significant deterioration in condenser vacuum. At wind speeds up to 13 mph, this recirculation can be managed by derating the steam turbine. This strategy keeps the steam turbine on-line, but it has reduced plant capacity regularly by as much as 40%.

To make matters worse, the reduced steam flow at these low loads causes the turbine exhaust temperature to operate precariously close to the 212F trip setpoint. Increases in wind speed above 13 mph are likely to result in a high exhaust temperature trip. Forced outages associated with this recirculation effect have been significant, occurring 2% of the operating year, and amounting to a loss of 338,000 MWh between January 1991 and September 1992. Extensive engineering studies are currently under way to combat this recirculation problem, including water-tunnel model tests, continuous meteorological data gathering, and an automatic steam-turbine unloader. The Matimba experience underscores that AC condensers must be properly designed and sited.

Keep tubes clean

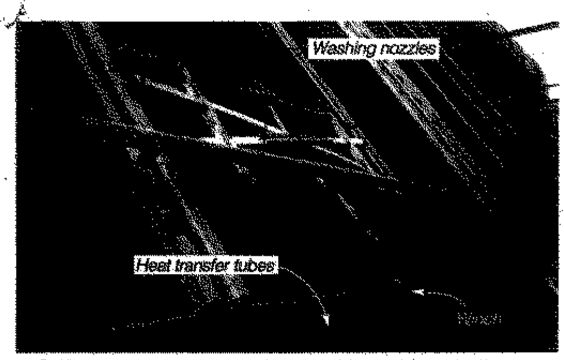
To minimize capacity losses, O&M personnel must maximize the heat transfer capability of the AC condenser. Common procedures include annual adjustment of fan pitch, semiannual evaluation of drive motor circuits, and quarterly inspection of gearbox mechanisms, including ferrographic lube-oil analysis. But the most important O&M procedure may be cleaning of the heat-transfer surfaces.

At the OLS Camarillo cogeneration

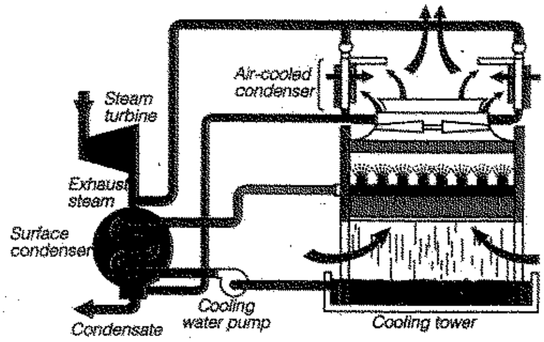


A. Dry-cooled condensers can be either direct-acting (top) or indirect-acting (bottom). Both use externally finned tubes

B. In wet-surface cooling, the second basic type of air-cooling, a water/air mixture cascades over smooth condenser tubes



2. Self-propelled waterwash device achieves thorough cleaning and operates while the plant remains on-line



3. Hybrid designs achieve better hot-weather performance than common air-cooled condensers achieve, but still use less water than conventional cooling towers

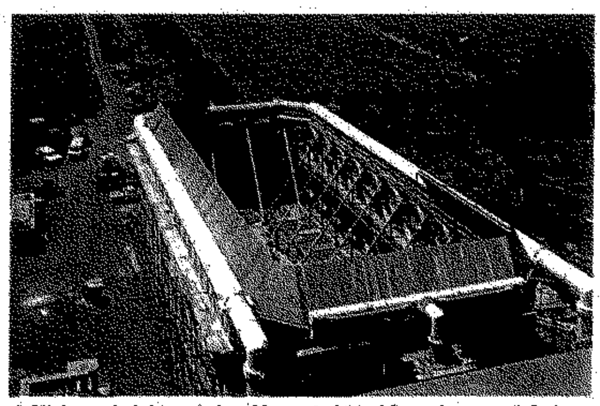
plant, owned by Energy Initiatives Inc, Parsippany, NJ, condenser vacuum improved by more than 2 in. H_2O the first time the tubes were water-washed. The Camarillo plant, operated by Stewart & Stevenson Operations Inc, Houston, Tex, is located in Ventura County, Calif, where it receives cool, onshore ocean breezes most of the year (Fig 1). But after the first two years of operation, Jeff White, plant manager, noticed condenser vacuum deteriorating, and initiated an annual cleaning schedule using 50-psig city water.

The wash is conducted only during extended outages when the condenser is cooled down, and only at night when ambient temperatures are low, in order to minimize evaporation effects that could leave deposits on the tubes. To even further minimize the possibility of deposits, White has considered washing with demineralized water, but corrosion would then become a concern. Based on the lack of visible deposition after three annual cleanings, the current precautions seem to be working well, without the added expense or corrosion potential that demin water incurs.

A unique AC-condenser wash program has been implemented at the Sayreville (NJ) cogeneration plant owned by North Jersey Energy Associates and operated by Westinghouse Operating Services Corp, Orlando, Fla. The plant crew has designed and installed a self-propelled waterwash device driven by a winch, pulley, and dc motor, and controlled by a variable-speed drive (Fig 2). The device washes one tube bundle at a time, which allows cleaning to be conducted while the condenser is still on-line.

The device—used once a year after the pollen season has passed and before the hot summer weather hits—makes two passes through each bundle. Jerry Wiegand, plant manager, reports that the device's effectiveness is visibly noticeable. On the first pass, the water stream only partially penetrates the tube bundle because of the deposits built up between the tube fins. But on the second pass, the stream shoots clear through the bundle, and sprays out the other side. When one bundle is completed, the lightweight device can be moved by a single crew member to the next bundle and the cleaning process starts again.

Using this technique, it takes approximately 10 days to wash all 128 tube bundles, which is considerably longer than off-line washing takes. The advantages are that the cleaning does not require a scheduled outage, and a more thorough wash is obtained because the device travels up and down the bundle at a rate smoothly controlled by a variable-speed drive. Maintenance Manager Doug Williamson and Plant Mechanic Rod Cimbalista were instrumental in designing the device and turning the concept into a reality. The system was used successfully in preparing for last summer's heat, and now is shared with other plants using AC condensers operated by Westinghouse Operating Services Corp.



4. Minimum height and visual impact of this AC condenser satisfied aesthetic requirements in Maui, Hawaii. Unique multiple-fan arrangement was designed by GEA Power Cooling Systems Inc, San Diego, Calif

Add evaporative capacity

If the plant crew has done all it can in terms of proper O&M and condenser vacuum is still insufficient, the AC condenser may need some help from the evaporative process. For example, the plant crew can rig up a temporary water spray directed onto the tube externals during the hottest days of the year. The water evaporates as it contacts the tubes, markedly improving the performance of the condenser, while still using only small quantities of water. But just as with the heat-exchanger washing process, care must be taken to avoid deposition on the tubes. For this reason, only water with total dissolved solids (TDS) below 10 ppm should be used. Jeff White uses this technique at the Camarillo site approximately 15 days each year to keep condenser vacuum above the 20-in. H_2O alarm point. The technique has been effective, reports White: In six years of operation, vacuum has never fallen to the 16-in. H_2O trip setpoint.

An extensive study was conducted on this topic in 1992 for the Matimba station. Eskom engineers first investigated the potential of using raw water for condenser performance enhancement. By studying the evaporation of water droplets as a function of relative humidity, initial droplet size, and traveling time, the researchers hoped to avoid wetting of the cooling elements and supporting structure to prevent deposition of solids. No practical configuration was found, so use of raw water was abandoned. The researchers next investigated corrosion and thermal behavior of finned tubes sprayed with demineralized water, with satisfactory results. Eskom engineers estimate they will be able to raise condenser vacuum by 4 in. H_2O by spraying the heat exchangers over a critical 300 hours/yr.

At least one manufacturer of AC condensers incorporates evaporative assistance into its air-cooled designs. The combination wet/dry system integrates an AC condenser and a conventional cooling tower into one structure (Fig 3). The supplier reports that this design allows a facility to meet low water usage requirements, while avoiding capacity losses during hot summer months.

Danger of freeze-ups

But it's not just hot summer months that pose challenges for operators of AC condensers. During the winter, freezing is a concern. Record low temperatures during this past winter left several US electric systems with unpredicted capacity shortfalls. AC-condenser problems were at least part of that story. For example, Virginia Power Co had to resort to a 5% voltage reduction and rolling blackouts when demand peaked the morning of Jan 19. One reason for the shortfall was the significant derating of Diamond Energy's Doswell facility because of a frozen AC condenser. The plant was derated from almost 700 MW down to about 80 MW.

The Doswell facility is a combined-cycle plant with four gas turbines and two steam turbines. When the AC condenser froze, the steam-turbine bypasses were opened, steam was vented, and the gas turbines were operated in the simple-cycle mode. But the vents can handle only a limited flow rate, so to operate in this mode, the gas turbines had to be throttled back. More important, continuous venting eventually left the facility short of water needed for the NO_x-control steam-injection system. To conserve injection water, the gas turbines had to be throttled back even further.

According to Sohi, the freezing incident began when natural-gas supplies were curtailed, forcing operators to shift to fuel oil. Difficulties in making this fuel shift diverted the operators' attention from the overall plant picture, and as a result, cooling fans were not turned off and heat-exchanger banks were not isolated when they should have been. When condenser vacuum suddenly deteriorates in the winter, the operator must recognize this as a symptom of freezing, and take the opposite action from that in the summer. With low ambient temperatures, deteriorating vacuum should trigger less heat transfer, not more. As Sohi summarizes, "Operator experience is very important in preventing AC condenser freeze-ups. Once localized icing begins, the entire condenser is frozen quickly—within hours."

To recover the plant, the AC condenser had to be thawed by portable heaters over a five-day period, and ruptured tubes had to be plugged. The plugged tubes were later replaced during a scheduled major outage.

In one respect, the Doswell facility was fortunate because the 150 ruptured tubes represented only a small portion of the overall total, so plugging was a satisfactory temporary measure. Peterson is familiar with a freezing incident that occurred at the Rosebud facility where plugging was not an option because of the number of tubes that ruptured. After the Rosebud event, the plant had to be shut down for three weeks to repair enough tubes to put the plant back on-line. Patching the externally finned tubes in the field proved to be quite a challenge for the crew.

Like the Doswell event, Rosebud's incident occurred in its first winter of operation, when operator experience was still limited and automatic controls were not yet precisely tuned. Problems with Rosebud's control system have since been corrected and the plant has not experienced another freeze-up. Peterson echoes the statement that freezes occur quickly, making early recognition the key to prevention. On that −30F Montana day, the condenser went from localized icing to near complete freeze-up in a matter of minutes!

Monitoring air leaks a must

Perhaps the most important freeze-prevention technique is monitoring of air leakage into the condenser tubes. An air leak can result in a localized air "blanket," which impedes steam flow through that tube. Without proper steam flow, individual tubes will quickly cool down and freeze. Peterson is confident that if there are no air leaks, there will be no AC condenser freeze-ups.

Most freeze-up incidents seem to occur in a plant's first year or two of operation. The experience factor is certainly a key here, but many plant managers also note that AC condensers may not be completely air-tight when constructed. A strict, methodical program to monitor and fix air leaks must be established before the first winter operating season. As a result of the freeze-up incident at Rosebud, the operators now record flow rates on the air ejector system whenever ambient temperatures are low. Monitoring how much air is being removed by the ejectors tells the operator how much air is leaking into the tubes. If the operators observe air leakage increasing, the mechanical vacuum pump is started up to assist the steam-driven air ejectors in maintaining vacuum, and an aggressive search for the leak is initiated.

Another method of monitoring air leakage is referred to as a "decay test." With the plant on-line, operators secure the air ejectors, and measure the rate at which condenser vacuum falls. If the rate exceeds the manufacturer's specification, then excessive air leaks exist. The Sayreville plant conducted both air-ejector monitoring and decay tests prior to its first winter, and found significant air leaks in the gland seal steam system. Identifying and fixing them before the onslaught of sub-freezing weather helped the AC condenser to successfully withstand the record low temperatures of this past winter. As Wiegand states, "You treat the AC condenser well, and it'll treat you well, too."

Gearbox, fan maintenance

Some sites are blessed with a lack of temperature extremes. For example, Maalaea Unit 15, owned by Maui Electric Co, Maui, Hawaii, never experiences freezing. But even in ideal locations, AC condensers challenge O&M personnel because of mechanical and electrical problems associated with the cooling fans and their drive mechanisms. The Maalaea plant, a 56-MW combined-cycle facility, has a total of 52 fans in its AC condenser. This large number of small fans was chosen rather than a small number of large fans, in order to minimize the height and visual impact of the condenser in this tropical paradise (Fig 4). But since plant commissioning in October last year, two gearbox failures have already occurred, and according to Ed Jackson, combustion turbine specialist, maintenance personnel are worried about keeping so many fans available during the upcoming summer season.

The O&M team also must pay attention to the pitch of the fan blades. Some sites have two different pitch settings, one for winter and one for summer, which must be adjusted prior to each season. Even plants with only one pitch setting have found it advantageous to annually measure and adjust the blade pitch to ensure the optimum angle of attack and to minimize imbalance problems that might lead to gearbox failures. Some plants rely on the manufacturer's service team to perform this measurement, while others handle it themselves, using a protractor and machinist's rule.

In addition to these mechanical problems, some sites have experienced fan-motor winding failures, attributed to the large number of starts and stops that an AC condenser fan experiences. Variable-speed drives are seen by some plants as an excellent solution here, but are often ruled out because of initial capital costs. ■

GEA Dry Cooling Systems

Dry cooling is becoming an increasingly common solution for powerplant heat rejection. Facilitating site selection because water supply is not an issue, shortening the permitting process (no water permit), and satisfying environmental regulations, dry cooling allows developers to place their plants closer to the source of their fuel, or closer to their loads. Dry cooling also eliminates the hazards of plume associated with wet cooling towers, thereby eliminating neighboring community concerns.

There are two types of dry cooling: direct and indirect. In a direct system, turbine exhaust steam is ducted directly from the turbine to an air-cooled condenser. In a two-stage, single-pressure condensing process, the steam flows through finned tubes positioned over forced-draft fans. As steam flows through the tubes, air is forced over the fins, initiating the condensation process. The condensate is collected and returned to the boiler feedwater circuit by a circulating pump.

In an indirect system (Heller System), exhaust steam is condensed using either a surface or, preferably, a direct-contact "jet" condenser. The cooling water or condensate is then pumped through finned-tube cooling "deltas" in either a natural or mechanical draft tower and recirculated back to the condenser. Because this is a closed system, the water does not come into contact with air and there is no need for makeup water.

The indirect system can also be delugeable. In deluging, a small amount of makeup water is sprayed over the finned-tube cooling deltas, increasing the overall heat rejection capacity of the system during hot weather, and decreasing turbine backpressure.

Reference plants

Linden Cogeneration Project

At this 614-MW combined-cycle plant in Linden New Jersey, the choice of heat rejection systems was dictated by geography as well as environmental constraints. A stringent permitting process, coupled with the dangers of plume made wet cooling impossible for the large cogeneration plant. Dry cooling with an air-cooled condenser made siting of the plant in this location possible.

When it was commissioned in 1990, the air-cooled condenser, a 60 cell structure covering two acres and standing 100 feet high, was the largest of its kind in the US and the second largest in the world. The massive unit ensured not only minimum water consumption, but also the elimination of any danger of icing on a nearby highway or a vision obscuring plume at nearby Newark Airport.

To meet local requirements for noise, the air-cooled condenser was installed with a low-noise air moving system utilizing sixty 30-ft-diameter fans.

Linden

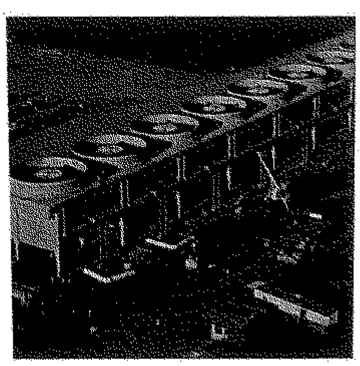
Taiyuan No. 2, Phase IV Cogeneration Plant Expansion

When plant management decided to add two 200-MW units to a six-unit, 250-MW, coal-fired district-heating/electric-power cogeneration facility in Shanxi province, China, cooling-system options were extremely limited. The city of Taiyuan's well-based water supply, which provides make-up for the six older units, is increasingly overtaxed, making dry cooling of the new units imperative.

Taiyuan No. 2's managers chose an indirect dry cooling system with a surface condenser. The cooling system for Taiyuan No. 2 is notable for its use of hot-dip, galvanized-steel finned tubes as the water-to-air exchanger, and the horizontal

GEA Wet Cooling Systems

Compared to dry cooling, wet cooling is a more-efficient way to reject a powerplant's waste heat, because water is a more-efficient coolant than air. There are two types of wet systems specified for powerplants today: once-through and evaporative.



Cope

Once-through systems, which dispose of waste heat by dumping it directly into a river, lake or sea, are simpler, less costly and more efficient than evaporative systems. But once-through systems have become a rarity, for two reasons.

First, to support industrial development, powerplants are increasingly built where water is scarce and/or costly. And where cooling water is abundant and free, strict environmental laws now prohibit thermal and contaminant pollution of aquatic ecosystems.

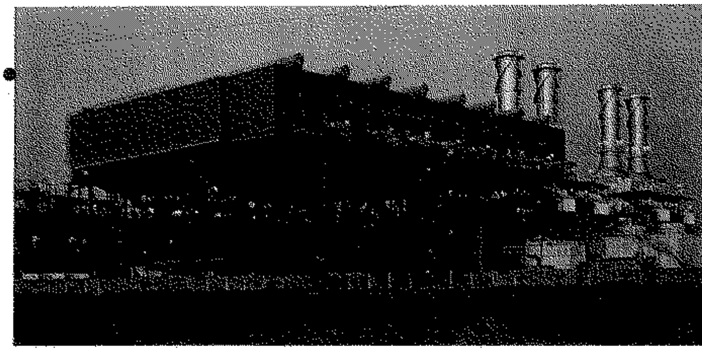
Evaporative wet cooling systems rely on mechanical-draft or natural-draft cooling towers. Mechanical-draft towers use large fans to draw ambient air into the tower and across the heat transfer media. Cooling takes place as a small portion of the circulating water flow is evaporated into the passing air stream. Because they have no fans, natural-draft towers are quieter and consume less parasitic power than mechanical-draft towers, but they are inherently larger and more costly, and may not provide the required cooling capacity.

Reference plants

The Cope Powerplant

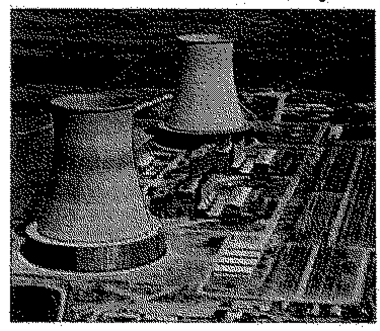
The precast concrete cooling tower serving the 375-MW Cope powerplant in Cope, SC (USA) has 14 cells in a single row with each 53-ft-wide x 45-ft-tall cell served by a 36-ft-diameter fan. The Cope cooling tower spans the length of two football fields. Erection of the 840 concrete members took less than three months.

Power Magazine



Uran III

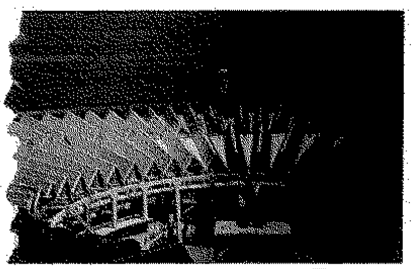
Trakya



arrangement of cooling elements in a conical shape inside the dry tower.

Trakya Combined-Cycle Plant
This 1200-MW facility in Hamitabad, Turkey, where irrigation of farmland consumes most of the scarce fresh-water supply, is the world's largest dry-cooled combined-cycle plant. Two separate indirect dry "Heller" Systems are used to cool Trakya's four 100-MW steam turbines. The tower-sharing configuration, as well as the low parasitic-power consumption of the fan-free natural-draft design, reduced the system's capital and operating costs far below those of other cooling alternatives, simplifying decision-making by Turkiye Elektrik Kurumu (TEK), Trakya's owner.

Commissioned in 1989, Trakya's dry cooling system has proven the value of several design innovations, including the installation of pre-heater/peak cooler cells inside the 443-ft-high hyperbolic towers. The cells, warmed by reversing fan rotations and closing louvers, provide freeze protection for the tower's cooling elements during winter start-ups. During peak-load summer operation, the same cells can be deluged with water to maximize heat rejection.



Taiyuan

Uran III Combined-Cycle Plant
By ordering two air-cooled condensers for its Uran powerplant near Bombay two years ago, India's Maharashtra State Electricity Board bought more than just a pair of direct dry cooling systems. The units allowed the utility to convert a gas-turbine installation that had been operating at a thermal efficiency of 30% to a combined-cycle facility with a power-generating efficiency of 46%.

The conversion to combined-cycle mode (Uran III) was effected by adding two 120-MW steam turbine generators to exploit the waste heat of the facility's eight gas turbines, installed in two phases as 4 x 60 MW (Uran I) and 4 x 108 MW (Uran II). Commissioned last year, the air-cooled condensers are a technological first for India, which has many power-hungry regions that lack access to clean cooling water.

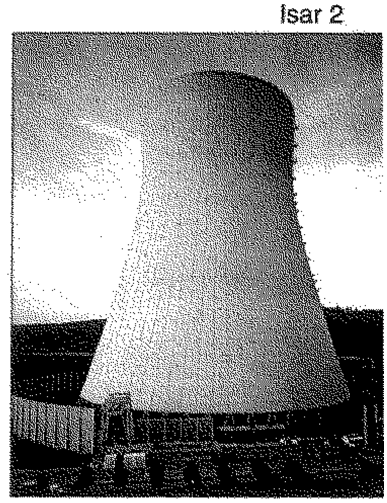
Isar 2 Nuclear Power Station
The natural-draft cooling tower serving this 1350-MW nuclear power station in Essenbach, Germany, is one of the world's largest; it stands 541 ft high, with base and top diameters of 502 ft and 279 ft, respectively. Because Isar 2 was designed to operate in baseload mode (more than 8000 hours each year), a less-expensive mechanical-draft tower, with fans incurring considerably higher per-hour operations and maintenance costs, was never considered a viable alternative.

The tower uses a proprietary upspray system which increases droplet dwell time in the spray zone. The upspray distribution system is also easier to maintain than a downspray system as dirt collects at the bottom of the distribution piping where it can be flushed out.

Also of note is a proprietary comb design that allowed pre-assembly of fill packs at grade level, thereby reducing the labor-intensive packing process inside the tower. The comb design also serves to hold the individual fill sheets in place and maintains their spacing during tower operation.

Schwarze Pumpe Power Station
Scheduled for commissioning in 1996 or 1997, this powerplant in the Brandenburg region of the former East Germany will use natural-draft wet towers to cool its two 800-MW lignite-fired generating units. Each tower will stand 462 ft high, with base and throat diameters of 341 ft and 201 ft, respectively. While providing a cooling range of 15 deg F, the towers will also cool the plant's twin flue-gas streams, using fiberglass-reinforced plastic piping to feed gas exiting the plant's SO_2 scrubbers into the towers.

Isar 2



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Gas-fired Plant Under Construction in Colorado

LCG, Mar. 6, 2002—A joint venture of Colorado Springs Utilities and El Paso Corp., of Houston, has begun construction of a gas-fired, combined-cycle 480-megawatt power plant just south of the Ray D. Nixon power plant, near Fountain, Colorado.

Steve Christensen, project manager at Colorado Springs Utilities, said the plant will lower the utility's need for purchases from the open market, and supply half of Colorado Springs' electricity needs during peak demand. The plant, named Front Range Power, is expected to be operational in spring 2003.

Colorado Springs Utilities, which has $40 million invested in the plant, said it will use 80 gallons of water per minute for steam turbines, compared to hundreds or thousands of gallons used by traditional gas-fired plants.

News Headlines

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What are the b
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removal and condensate recovery. The new design, marketed as Steamflo, differs from Hudson's traditional Stackflo ACC, in which steam is condensed inside finned tubes (Fig 2). In the new Stackflo design, steam is condensed on the outside surfaces of heat-pipe tubes. While ice can still form on the outside surface, freezing and thawing will not result in any damage, according to Hudson.

The Stackflo system also incorporates a steam duct near grade that collects condensate that is always in contact with saturated steam. This minimizes subcooling of the condensate, which in turn improves overall cycle efficiency. Heat is rejected to the air from a conventional finned tube bundle (heat pipes) and induced draft axial flow fan. Ammonia heat pipes are the basic heat-transfer element of the new steam condenser, and consist of a sealed pipe containing ammonia working fluid.

ACC announcements. Dry cooling was selected in several recent new-construction projects, including two awarded to Black & Veatch, Kansas City, Mo. In January, Black & Veatch announced that it has joined with H B Zachry Co, San Antonio, Tex, in a joint venture agreement to provide full design, procurement, delivery, construction, startup, testing, and initial operation of Reliant Energy Co's (Houston, Tex) Choctaw County project, located near French Camp, Miss. The ACC will be supplied by GEA Power Cooling Systems Inc, San Diego, Calif.

According to Black & Veatch, use of the ACC will reduce the overall project water consumption to less than one-tenth of the water used for a corresponding combined-cycle plant using conventional cooling towers. The Choctaw County project will be one of the largest uses of an ACC on a combined-cycle plant in the US. The plant features a 3-on-1 design comprised of three GE 7FB gas-turbine generators; three triple-pressure reheat cycle heat-recovery steam generators, and one reheat condensing steam/turbine generator for a total nominal capacity of 800 MW. Commercial operation is scheduled for June 2003.

In March, Black & Veatch announced it has joined with Barton Malow in a joint venture agreement to provide full design, procurement, delivery, construction, start-up, testing, and initial operation of another Reliant Energy project, Hunterstown, located near Gettysburg, Pa. The plant will be equipped with another GEA-supplied ACC, this one featuring the manufacturer's new reduced-noise fans. The fans are designed for low-velocity air flows and are enclosed in unique hoods that cut noise. The lower air flows are compensated for by extra heat-exchange surface area to retain full condenser capacity. Like Choctaw County, Hunterstown will be a 3-on-1 combined-cycle design, nominally rated 800 MW, with commercial operation scheduled for June 2003.

A little o' both

In between wet and dry cooling there are several hybrid designs and modifications to existing systems. MassPower's Indian Orchard cogeneration plant has one such system, called a wet-surface air condenser. A large duct carries steam between the low-pressure turbine exhaust and tube bundles, where water is sprayed on the outside of the tube. The water falls to a basin. Fans in the middle of each cooling cell draw air horizontally through the tube bundles and then into the atmosphere (Fig 3). This configuration significantly reduces the plume and tower drift. Both were a concern, as the plant is located in a valley next to a major road. The plume and tower drift could have caused visibility problems and icy driving conditions.

Other hybrids include dry cooling systems fitted with spray nozzles to provide evaporative cooling on the hottest days, and recirculating systems with air coils similar to the dry systems located just below the tower's inductance fan. This not only provides additional cooling, it also decreases the plume. ■

Power 9/02 P59

Cal Energy Commission
Elk Hills Project
Testimony of Dr. Fox

information in the opening and reply briefs, and presumably the testimony may be going -- that was just invited to be given, would cover the reply as well as the opening briefs. The reply brief is the subject of the motions that we discussed this morning, and I would like to just reconfirm the scope of the hearing at this point, until those motions are ruled upon, is the issues of wet versus dry costs, and economically unsoundness, as was requested by Commissioner Moore.

So since the reply brief in its entirety goes beyond that, I just wanted to caution that I would -- hopefully we reach agreement that the testimony would not go into the areas at this point that are subject to the motions to strike and to limit.

MS. POOLE: And Dr. Fox does intend to discuss the economic --

PRESIDING MEMBER MOORE: I think that fairly restates what I had in mind, and I'm assuming that Ms. Poole and her client will respect that. So, yes.

MR. MILLER: Thank you.

BY MS. POOLE:

Q Would you please summarize the

information?

A Now, we're talking about the opening brief.

Q We're talking about the arguments concerning economic soundness and cost comparisons for dry and wet cooling.

A I did a cost analysis, which is included in the opening brief, using the information in the AFC. I used a series of programs put out by ThermoFlow. ThermoFlow is a Massachusetts company which develops and markets software which is widely used in the power industry to design and cost power plants.

Mr. Rowley characterized these programs that I used as, quote, models, and the term model is really a term of art which carries with it certain generally adverse connotations. For example, there are air quality models and water quality models that seek to simulate different conditions. There are economic models that seek to simulate entire economies. And most people recognize the fact that models are only that, a simulation and nothing more, and they can be quite inaccurate.

The programs that are produced by

ThermoFlow are not really models. They are heat balance and costing programs. They do nothing more than the calculations that an engineer would do with a pencil and a piece of paper, except they accelerate that process.

For example, GT Pro, which is one of these programs, produces the heat balance for a power plant. And what we did was we took the heat balance, which is included in the AFC, and simply reproduced it in ThermoFlow. Simple exercise. Doesn't involve any modeling or wild assumptions. It simply reproduced information presented by the Applicant in its AFC.

That simulation then is dumped into a second program called GT Master, which fixes the hardware, again using information from the AFC. And the output from that is dumped into a costing program which calculates the cost, doing exactly what an engineer would do with pencil and a piece of paper, and information from vendors.

I used that series of programs, and the Applicant's heat balance and equipment sizing data from the AFC, to determine the effect of dry cooling on the profitability of the Elk Hills Power project. We chose, instead of looking at net present value or other possible economic measures, we looked at what a lender would look at in evaluating whether or not a project is suitable for financing. And what a lender looks at is not net present value. A lender will look at the internal rate of return, or the IRR.

And the ThermoFlow programs allow you to calculate that. And in making the calculations, we did not attempt to second guess what the Applicant's assumptions were with respect to any of the financial parameters that go into those calculations. The model comes with built-in industrywide assumptions. And we held those constant, and the only thing that we substituted was the Energy Commission's very own forecasts for the price of electricity and the price of natural gas, and the rate of inflation.

The Energy Commission recently did its own study to evaluate the economic viability of the merchant plants that are currently being proposed. The study was published in February of this year, and it's on the Energy Commission's Website. And we took the financial assumptions that the Energy Commission staff itself developed, together with engineering costing data, based on

Fox

the AFC, and forecast what the impact of dry cooling would have on the internal rate of return of the Elk Hills Power project. And the results of that analysis indicates that dry cooling would reduce the internal rate of return by about one-third of a percent. In other words, it's minor. We are not claiming, as the Applicant and staff have suggested, that dry cooling comes without a penalty. It certainly does come with a financial penalty. It's primarily due to the loss of electrical output from the increase in backpressure. There's no dispute over that fact.

However, you can take your penalty in two ways. You can take your penalty in terms of reduced electrical output, which means you lose revenue on the hottest days, when you want to sell it, or you can take your penalty in terms of increased fuel consumption. You can actually offset the loss in electrical output by cranking up the duct burner and simply firing it more.

What we found from running the Peace program, the model that calculates the costs, is that it is generally more cost effective to take the hit in electrical output as opposed to cranking up the duct burners, because the duct burners are not as efficient as the rest of the power island.

Anyway, in sum, we agree that there is a financial penalty associated with using dry cooling, and that translates into a reduction in the internal rate of return of about a third of a percent.

Q Dr. Fox --

PRESIDING MEMBER MOORE: Ms. Poole, before you go to your next question, can I just ask one question of Dr. Fox, and that is, in terms of the heat balance model -- and I'm very familiar with the term models -- I'm not sure I wouldn't object to the idea that they're -- they always produce a nega produce a negative resu nse that they simply simulate someone's vision of reality, whether it's mine or anyone else's. But in order to calculate IRR, someone putting that model, or the -- or the statistical package together, had to make some assumptions about capital costs. I mean, isn't that correct?

I mean, built into that, whether it's invisible to the user or not, would have to be some set of standardized or routinized assumptions